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Summary of Inservice Test Program Issues/Concerns Identified During Recent Assessments/Updates at Various Nuclear Stations

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ABSTRACT

Over the last few years, True North Consulting (TNC) has either assessed or been involved in the overall development, review, and/or update of numerous Inservice Test (IST) Programs. These IST Programs have been at both primary types of reactors; Boiling Water Reactors (BWRs) and Pressurized Water Reactors (PWRs), and have included all of the major US Nuclear Steam Supply System manufacturers and designers; Westinghouse (3 and 4 loop), Combustion Engineering, Babcock & Wilcox, and General Electric NSSS throughout the US and abroad. This paper attempts to identify the more common issues/concerns and questions identified during the development, implementation and review of these IST Programs. For the most part, these findings reflect the various plants' implementation of the IST Program using the 1987 edition/1988 addenda of the American Society of Mechanical Engineers (ASME) *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code). However, more recent findings have been identified and included in this discussion to bring the findings "up-to-date" with the latest issues and concerns identified by facilities using later editions of the OM Code. Primarily the 1995 edition/1996 addenda through the 1998 edition/ 2000 addenda of the OM Code have been included in this discussion.

The primary purposes of this paper are to provide a platform for discussion of reoccurring IST Program findings, review these findings from a combined larger sample perspective, and to share industry/regulatory guidance or proposed resolutions to many of the problems identified during these IST Program reviews/assessments. The overall objective and hope is that this presentation will provide the industry with a general understanding of issues/concerns identified during development, implementation and maintenance of IST Programs using requirements and industry/regulatory guidance available to ensure that IST Programs are in accordance with requirements of the OM Code and the intent of the Code as delineated by industry and regulatory guidance where applicable.

Since the 1980's, utilities have been trying to successfully and, cost effectively implement requirements of the ASME OM Code (or in earlier years, Section XI), as required by the Code of Federal Regulations, 10 CFR 50.55a. The ASME and the NRC have made great progress in attempting to provide guidance and direction to the industry as a whole; however, many questions still require resolution and/or clarification, to ensure consistency and standardization are reflected in the development, implementation, and maintenance of IST Programs. This approach to IST would result in improved quality and technical adequacy of IST Programs, as well as an overall increase in the reliability and availability of safety related equipment. This will improve overall safety and reliability of nuclear facilities and assure continued support for the nuclear industry as a viable energy option.

To this end, True North Consulting has compiled a list of the most frequent issues and concerns identified during the last few years, along with those methodologies (some questionable) adopted by the industry and regulatory agencies in response to these issues/concerns. It is our belief that, through identification of these frequently occurring issues/concerns and through the described implementation of standardized resolutions that, the ability of IST to assess operational readiness of safety related equipment and systems will be improved.

The paper will first provide a brief general discussion of IST issues/concerns which have been identified using guidance provided by various industry and regulatory documents. This will be followed by a discussion outlining specific issues/ concerns within each of three primary IST areas: general requirements, pumps, and valves (including safety and relief valves). The paper will conclude with a discussion regarding issues and problems identified by various NRC Generic Letters, and Information Notices issued over the last few years.

It should be noted that positions taken or stated within this paper are those of True North Consulting and do NOT necessarily reflect those of the NRC or the ASME.

Introduction

Over the past several years True North Consulting has been involved in many aspects of IST Programs, from development of IST Bases documents to updating of IST Programs/Plans to later editions of the OM Code, basic IST overview training, and numerous IST Program and Program Implementation assessments. We have performed these activities on all types of nuclear power facilities (PWRs and BWRs) and virtually all individual NSSS vendor plants (General Electric, Westinghouse, Babcock & Wilcox, and Combustion Engineering). During this period of time, several "recurring" issues and concerns have arisen and continue to be problematic to the nuclear industry. In addition, as a result of the recent OM Code changes, new issues and concerns have been identified associated with the more recent Code requirements in later editions of the OM Code.

It is the intent of this paper to bring to the attention of both the industry and regulators, these issues/concerns which have been previously identified and are continuing to occur, as well as to provide the industry a platform for discussion of some clarifications and guidance already available which may help less experienced IST personnel avoid previously identified areas of concern. It is also the intent to initiate a discussion of more recent questions and problems which have come to light, with the hope of providing a clearer understanding of the "roadblocks" associated in development, implementation, and maintenance of IST Programs, and to identify areas where additional direction to the industry from the regulators and the ASME may be needed.

In some cases solutions proposed to resolve issues and concerns have been stated which may or may not reflect positions held by ASME or regulatory authorities having jurisdiction at the sites. These resolutions or recommendations are only presented as possible guidance or information to be used for resolution of stated issues/concerns identified during these discussions. As many facilities are either currently performing IST upgrades to their existing programs or are contemplating ten-year updates within the next few months, many of these issues and concerns may provide utilities with a clearer understanding of existing issues and thereby prevent the utilities from having to unnecessarily pursue avenues which may not be adequate or which may not provide acceptable solutions for these concerns.

General Regulatory/Industry Concerns

One of the most important aspects of ensuring IST Programs are in compliance with existing regulations is to ensure the scope of each component has been adequately determined by the use of approved regulatory requirements and industry and regulatory guidance.

Scope

Determining the scope of the IST Program continues to be one of the most difficult and problematic areas associated with development, successful implementation, and maintenance of most IST Programs. A large majority of facilities have developed IST Bases Documents to assist in this endeavor, but many of the Bases documents provide inadequate or incorrect scoping guidance. Several factors contribute to this issue some of which include differences in plant design, when the facility was designed and constructed, plant licensing documents, commitments made to regulatory authorities prior to operation of the facility, and changing or unclear regulatory and/or industry guidance. The NRC has attempted to provide guidance to nuclear power plants (NPPs) through various documents issued and actions taken at numerous sites. Attempts to provide guidance and directions regarding scope of IST Programs have included Generic Letter (GL) 89-04, Supplement 1 to GL 89-04, NUREG 1482, additional workshops and symposiums (specifically the NRC Workshop Summary provided in 1997 regarding IP 73756), as well as specific Information Notices (INs)/Bulletins (IEBs), to name a few.

One of the most proven and sound methods of ensuring that a satisfactory IST Program is developed, implemented and maintained is to first develop a detailed IST Bases document. The development of a detailed IST Bases provides a solid foundation and understanding of the safety functions of the various components and systems at the facility. It is recommended that the IST Bases be developed using guidance and direction provided by regulatory and industry documents. Additionally, performance of "peer evaluations" and independent assessments provide further assurance of scope, compliance and cost effectiveness of IST Programs.

Although guidance on scoping and classification for components has been provided by both 10 CFR 50.55a and other regulatory documents such as Regulatory Guide 1.26, NUREG 1482, NUREG 0800 section 3.3.2, and others, many utilities continue to have incorrectly or inadequately scoped boundaries and IST Programs.

One major solution to these "scope" issues that the NRC could provide is to issue "clear and concise" guidance as to the term "accident" and what is meant by this term. Although industry/regulatory guidance has been provided in the past, there are several contradictions and inconsistent practices being used throughout the industry. Even amongst stated guidance, there is "contradiction" and disagreements as to the "meaning" of some scoping statements.

Another primary reason for scoping discrepancies is the significant turnover rate experienced in IST personnel. On average, somewhere between 30-50% of IST Engineers change positions every 2 or 3 years. This results in having a highly significant turnover rate of roughly 75% every 5 years. Many utilities resort to "tribal knowledge" in order to maintain their IST Programs without understanding the underlying "intent" of the Code or the regulations. This results in inadequate or incorrect "interpretations" of Code requirements being promulgated throughout the industry.

One way facilities could deal with this excessive turnover rate and the problems created as a result is to ensure that adequate training and documentation is provided to not only the present IST Program Manager, but to "backup" engineers and staff as well. This would ensure that the IST Program is able to be maintained using acceptable and established Program requirements developed in accordance with industry/regulatory guidance and requirements. Additionally, facilities (and their contractors) need to ensure IST Programs are developed, implemented and maintained using industry/regulatory requirements and guidance rather than developing "individualized" IST Programs.

Finally, facilities need to ensure the Scope of components for IST, as identified in 10 CFR 50.55a, and guidance provided in NUREG 1482 as well as other acceptable resources and documents, has been thoroughly researched and documented as to the inclusion/exclusion of components in the IST Program. These documents should be maintained in accordance with established facility procedures and controlled by the IST Program Manager in accordance with approved station procedural requirements. This will ensure that, with indifference to changes in plant personnel, changes in plant design will be evaluated to ensure continued maintenance of IST Program scope and that Code/regulatory compliance will be maintained.

The understanding of IST "intent" and the terminology used in IST are other significant contributors to scoping issues and concerns.

Again, this lack of understanding could be alleviated by the ASME and regulators providing clear and unambiguous definitions to some of the terminology used in development, maintenance and implementation of IST Programs. For example, several terms continue to cause problems in determining clear requirements for IST Programs. Terms such as practical, practicable, design flow, accident, etc. These ambiguous and sometimes confusing terms continue to prevent consistent implementation of OM Code requirements. Further, facilities not providing adequate, timely and "position specific" training to not only IST personnel but all plant staff personnel who are required to "understand" the various IST requirements associated with successful implementation of IST Programs also contributes to the inability of many utilities to satisfactorily implement regulatory and Code requirements regarding the IST Program.

Other causes for the inability of NPPs to adequately develop scope of IST Programs include lack of ownership, lack of management involvement and control, "hostile environs", etc. Recently, regulators and the ASME have attempted to provide additional clarification and unambiguous guidance regarding scoping of IST Programs. The industry must also share in the responsibility for the lack of consistent and adequate guidance, but the recommendations stated above, if incorporated, would go a long way in resolving many of the existing scoping issues/concerns identified, and would provide a "platform" for the next evolutionary phase of IST (the implementation of performance based and risk informed testing).

Examples of Scope Issues/Concerns Identified

Numerous examples of facilities misinterpreting or misunderstanding the scope for components which should be tested under the IST Program are available. Some of these examples are listed below.

One facility was testing common header check valves used in the Standby Liquid Control System in the IST Program. The plant's Design Bases Document (DBD) stated check valves were required to pass a minimum of 80 gallons per minute (gpm). The plant's IST Program had the check valves listed as Class 2, Cat. C and were included in the IST Program. The check valves were being tested using only one Standby Liquid Control Pump during refueling outages. One Standby Liquid Control Pump was ONLY able to provide approximately 60 gpm. When this concern was identified, the owner concurred with the finding and was immediately involved in determining corrective actions which included revising the IST test to adequately test the check valves to their "full open" position, as required by the OM Code and clarified by GL 89-04. However, as the facility "queried" others in the industry, the final response to the identified concern was that the "accident" (Anticipated Transient Without Scram, ATWS) for which the Standby Liquid Control System (including the subject valves) is credited, is "beyond the IST Bases" as the "accident" is NOT listed in Chapter 14 (15) of the Technical Specifications. Therefore, the method used to test the check valves is adequate and the valves were removed from the IST Program.

Another example of this lack of understanding of the scoping for IST components was identified when a facility's Diesel Generator (DG) support systems (DG Fuel Oil Transfer, DG Air Start) were listed as non-Code components (older facility) and not identified as Class 3 components. As a result, none of these components were identified as requiring inclusion into the IST Program nor were any of these components tested in a way to be able to satisfy "operational readiness."

One facility, having stated in the Design Bases that the minimum recirculation valves used in the Auxiliary Feedwater (AFW) system to provide protection to the AFW pumps were required to open in order to prevent damage to the AFW Pumps as a result of the primary flow path being isolated, did not have these valves listed in the IST Program. Upon identifying this concern to the IST Manager, the resolution to the finding was to CHANGE the DBD to state that the mini-flow valves are NOT required to prevent AFW pump damage, because the AFW pumps would NEVER be in that condition. This was due to the fact that, as the DBD was revised to state, "...the AFW pumps had isolation valves that would Open upon receipt of a safety signal and, even should the isolation valves on one train fail to Open thus rendering one pump inoperable, there are two other AFW pumps that would still be able to satisfy the safety function of the AFW system. This safety function is to inject feedwater into the steam generators to prevent the steam generators from being "blown down, thus rendering the primary heat sink inoperable."

As can be seen from the few examples above, there is clearly a lack of understanding of the scoping requirements for IST components which resulted in, or at least contributed to, the identified issues/concerns observed at several of the stations and described above.

General Requirement Issues

Several general issues/concerns have been identified throughout the IST area which have resulted in numerous problems for the facilities. These have ranged from questions being responded to incorrectly to Code noncompliances and violations being identified with resulting actions taken by the NRC. These include pre-conditioning and skid-mounted components.

Pre-conditioning

Pre-conditioning, the act of NOT testing a component in its "as -found" condition, has been identified over the last several years as a concern at many facilities. The NRC attempted to bring this concern to the industry's attention in 1997 by issuing Information Notice (IN) 97-16. Within the IN were descriptions of what was "acceptable preconditioning" and what may be considered "unacceptable preconditioning". As a result of the IN, the ASME Code Committee looked at possible ways to "define" or provide some additional guidance to the industry, as to what was "acceptable and unacceptable preconditioning". After numerous discussions and proposed definitions however, it was determined that the NRC had provided sufficient guidance within IN 97-16 regarding preconditioning and no additional action or guidance should be taken or provided by ASME. Many Code Committee personnel identified the "preconditioning" as a "deliberate" act. As a result of this "stipulation", the regulators had concerns associated with determination of "intent". This led to the Code Committee action to define or provide additional guidance regarding preconditioning being dropped, and no further action taken by either the ASME or the NRC.

Clearly, the industry had concerns and questions with the lack of further action taken by ASME or the NRC regarding the preconditioning issue, and confusion still exists today as to preconditioning and its affect on IST. TNC has been requested by several utilities to provide guidance as to the preconditioning issue and it is clear the industry in general would like to see further action taken on attempting to define or at least clarify preconditioning and when it would be acceptable.

At the recent Inservice Test Owners Group (ISTOG) meeting, this was further identified as an industry concern. This issue was also discussed at the last Code meeting in December 2003. It is clear from all indications that this issue is not going to go away.

From a practical standpoint, a realistic and scrutable definition of preconditioning would appear to be that "certain preconditioning of components is acceptable provided, the action does NOT affect ability of the facility to detect and monitor for degradation or, in other ways interfere with the ability of the facility to determine operational readiness of a component."

Several utilities have provided "technical positions" regarding preconditioning and many of these upon further review were found to be adequate. There are however, many other utilities who were found to have a lack of understanding of preconditioning in relation to IST.

Skid-Mounted Components

During the late 1970's and early 1980's, numerous relief requests were submitted to the NRC in an attempt to provide or suggest alternate testing methods, or exemption from IST, for certain components which were "mounted" or otherwise connected to a primary components which provided safety functions and were required to be tested in the IST Program, but which were extremely difficult, if not impossible, to test in accordance with the requirements of the OM Code. Primarily, at least initially, these components were associated with Diesel Generator Support Systems such as Fuel Oil, Air Start, Jacket Water Cooling, etc. In addition, solenoid valves used to support air operated valve functions were also included in this scope. Typically, these components were unable to be individually tested as components but were “functionally tested” as a result of testing of the primary components (e.g., DG monthly test, IST testing of the AOVs, etc.).

The NRC in GL 89-04 attempted to provide guidance to the industry concerning “skid-mounted” components and further guidance was provided in NUREG 1482. More recently, the ASME OM Code has been revised to specifically define “skid mounted” components and to provide an exclusion for these components from the IST Program, provided certain conditions are satisfied. These conditions for exclusion are primarily that the components satisfy the definition of “skid-mounted” and, the component is adequately “functionally tested” during testing or operation of the primary component. For example, the solenoid valve is adequately “functioned” when the air-operated valve (AOV) is tested or exercised, even though stroke time or position of the solenoid-operated valve (SOV) is unable to be readily determined or measured.

There are several examples of the “skid-mounted” requirement or definition being incorrectly interpreted or understood. One facility used the “skid-mounted” exclusion to exclude all Diesel Generator (DG) Support components (Starting Air, Fuel Oil, etc.) from IST on the basis that the components ONLY supported the Diesel Generator and therefore were excluded from IST. Even though some of these components did indeed satisfy the IST “skid-mounted” exclusion criteria, there were others (DG Fuel Oil Transfer Pumps and associated valves and, DG Air Start Accumulator check valves) that were NOT “skid-mounted” or did not fully satisfy the IST definition for exclusion of “skid-mounted” components as stated in NUREG 1482, or the later editions of the OM Code.

Component Testing Issues

Pumps (ISTB)

To a large extent, many of the typical pump issues/concerns previously identified in past IST program reviews and assessments have either been eliminated as a result of changes made to the OM Code, or have been so well identified and documented in the various regulatory and industry documents published (i.e., NUREGS, INs, etc.) that the issues/concerns have been virtually eliminated. However, as a result of the recent changes to the OM Code, Subsection ISTB, there have been a few new issues added to the list. Primarily, these new issues/concerns are a result of the new methodology and requirements used in performing IST on pumps; in particular, the comprehensive pump testing requirements stated in the later editions of the OM Code.

Exclusions (ISTB-1200)

There continue to be areas of concern associated with the exclusion/inclusion of driver bearings. Several attempts have been made by the OM Code Committee with regards to clarification of what bearing vibration measurements are required by IST and when and how these bearing vibration measurements are required to be taken.

In particular, the distinction between “rigid” and “flexible” couplings appears to be a general point of confusion. The OM Code Committee and the NRC have attempted to clarify the terms in NUREG 1482, and the NRC Workshop Summary, but there still exists confusion among many of the utilities.

In 2003, the OM Code committee revised ISTB-1200 to further clarify the exclusion by defining the term “flexible coupling” as a coupling which does not allow transmission of vibration loads to the pump. However, since this Code change has not been approved by the ASME, it has not yet been incorporated into the OM Code. It does, as presently written however, provide for a clearer understanding of the term.

Pump Categories (ISTB-1300)

Primarily, the issue/concern associated with this Code requirement is the clear understanding of pump categorization, and when a pump (with multiple safety functions) is a Group A or B pump. In addition, “intent” of the overall pump testing philosophy with regard to the various required tests is also a question being raised at several facilities.

Preservice and Inservice Testing Requirements (ISTB-3100 and ISTB-3200)

One of the primary issues/concerns identified with the later edition of the OM Code is the distinction between Preservice and Inservice testing and the various requirements associated with each.

For example, when a Group B pump undergoes “major maintenance or repair” online, what type of testing will satisfy the requirements of the OM Code, in particular Subsection ISTB-3310. ISTB-3310 requires that, should a reference value or set of values be affected by repair, replacement, or routine servicing of a pump, a new reference value or set of values shall be determined in accordance with ISTB-3300, or the previous value reconfirmed by a comprehensive or Group A test being run before declaring the pump operable. In addition, it is up to the owner to determine if a "pump curve" is required to be developed to satisfy ISTB-3100 requirements.

The issue associated with this requirement is apparent when the repair/replacement is performed on a Group B pump, with no practical way to satisfy the requirements of ISTB-3310 regarding the performance of a Comprehensive or Group A test. The question then becomes how are we able to return the pump which has undergone "major maintenance" to an operable status? Several proposed solutions have been put forth at recent meetings of the OM Code Committee. One of these proposed solutions allows that a Group B test be run on the repaired pump and using the results to "declare the pump operable" pending performance of a Comprehensive test at the next Cold Shutdown. Another of these proposed solutions is to provide justification to the NRC in the form of a relief request on an expedited basis for regulatory approval. Neither one of these proposed solutions has as yet been approved by either the OM Code Committee or been endorsed by the NRC.

Reference Values (ISTB-3300)

Another reoccurring issue/concern identified is associated with the term "pump design flow." Presently, "pump design flow" as used in the OM Code, is NOT defined by the OM Code. Many utilities and regulators have interpreted this term to mean the "Best Efficiency Point" or BEP of the pump, as identified typically on the manufacturer's pump curve. The primary intent of this term regarding IST of pumps, is to ensure the pump is tested on a portion of the pump curve as to allow for the timely detection and monitoring of degradation. Many facilities continue to use the bypass loop and other restricted flow paths, as a reference point for IST. In many cases, this reference value is at or near the shutoff head of the pump and therefore provides little or no ability for the detection or monitoring of pump degradation.

Recently, the OM Code Committee has provided clarification for the "pump design flow point", which should satisfy the intent of the Code, and provides an acceptable method to be used to support IST pump testing. Again however, it needs to be noted that definition for "pump design flow", or the associated Code change, has NOT been approved by the ASME or the NRC and therefore caution is urged in the use of this definition or clarification.

Data Collection (ISTB-3500)

Many facilities continue to use instrumentation that does not satisfy requirements of the OM Code or industry/regulatory guidance provided in various documents including NUREG 1482, the NRC Workshop Summary, and various Code interpretations. The determination and implementation of acceptable instrumentation for pump testing continues to be an issue/concern throughout the IST community. Several changes to the OM Code have been made to provide additional guidance and clarification in the use of instrumentation and the allowances of various "alternatives".

Bypass Loop Flow (ISTB-5100, ISTB-5200 and ISTB-5300)

An area which continues to be identified as an issue/concern is the continued use of "bypass" or "minimum recirculation" flow loops for Quarterly pump tests required by ISTB. In later editions of the OM Code, bypass loops and flows have been defined and clarified by the ASME, however, several issues have been identified with continued use of bypass flow loops for Quarterly IST. Hydraulic parameters are still required to be "fixed" and the variable parameter is still required to be measured, when performing Quarterly Group A or B pump tests. In particular, many PWRs have pumps which are unable to be tested Quarterly using installed instrumentation. Previously, relief was granted using Generic Letter 89-04 Position 9, which allowed the use of non-instrumented minimum recirculation or bypass lines for Quarterly testing, provided the pumps were able to be tested at least once every cold shutdown or refueling outage using a "full" or "substantial" flow path which was instrumented in accordance with the Code requirements. Several regulators have questioned continued use of GL 89-04 positions and NUREG 1482 guidance, due to the fact that the guidance is somewhat "dated". This position has presented somewhat of a concern to some utilities. It is somewhat unclear and of a concern why the use of GL 89-04 positions are being questioned at this time. Generic Letter 89-04 did not have a specified time limit and, therefore, the numerous positions delineated in GL 89-04 and incorporated by the industry should still be valid. Many positions set forth in GL 89-04 have been incorporated into later editions of the OM Code, but there are some not yet incorporated into the Code. As a minimum, positions put forth by GL 89-04, unless proven unacceptable, should be allowed to be referenced in revised IST Programs as applicable, and used as a reference for IST program submittals as a "continued justification" for certain alternatives. This should be acceptable unless the regulators deem it appropriate to formally issue subsequent rules or additional guidance to the industry regarding the use of positions delineated in GL 89-04.

Valves (ISTC)

As with the pumps, to a large extent many of the typical valve issues/concerns previously identified in past IST Program reviews and assessments have either been resolved, as a result of changes made to the OM Code, or have been so well identified and documented in the various regulatory and industry documents published (i.e., NUREGS, INs, etc.) that issues/concerns have been eliminated. However, as a result of the recent changes to the OM Code, subsection ISTC, there have been a few new issues/concerns which have been identified. Primarily, these new issues/concerns are a result of the new methodology used in performing IST on check valves, in particular, bi-directional check valve testing.

Exemptions (ISTC-1200)

There continue to be areas of concern identified with inclusion of manual valves in the IST Program. Many facilities do not have adequate IST bases for the determination of the testing requirements for manual valves. Others do not understand that testing (including position indication and exercising) is required to be performed on manual valves, which have safety functions applicable in the scoping of IST Programs. There also appears to be confusion as to what constitutes a passive or active valve for the manual valve population.

In addition, recently, primarily as a result of Generic Letter 96-06, several facilities are incorrectly or inadequately testing valves in the IST Program for a safety function other than for what the valves were originally designed. For example, several facilities are crediting AOVs for “relieving” pressure from Containment Isolation penetrations in lieu of adding relief valves or simple check valves for this over-pressure protection. The primary concern associated with this is that, in many cases, the AOVs are NOT tested to adequately ensure the disk would “lift” to prevent potential over-pressurization of the penetration. From a practical standpoint, the AOV is essentially being relied upon to fail to seat, or the valve is being required to lift off the seat in order to resolve or address the over-pressurization concerns identified in GL 96-06.

Control valves continue to be “exempted” from IST programs, even though the safety function of the control valve is to Open or Close and NOT just to “modulate.” This issue/concern has been identified previously in NUREG 1482, and the NRC Workshop Summary. In addition, clarification has been provided in the OM Code to further address this issue. A Code Case (OMN-8) has also been issued to allow an alternative to the rules for preservice and Inservice Testing of power operated valves used for system control and ONLY have a fail-safe safety function.

In the Code Case OMN-8, the alternative to stroke timing and fail-safe testing of specifically identified control valves is to allow the valve to be “exercised” in lieu of stroke timing testing requirements and acceptance criteria as stated in the OM Code.

Valve Categorization (ISTC-1300)

Categorization of certain valves continues to be a concern, especially when the valve has more than one category function. Examples include valves which are used as relief devices as well as power operated valves; simple check valves used as relief devices; and power operated valves used with Category A and Category C functions. In many cases, only one of the functions is tested or, in other instances, tested in a manner not able to satisfy the requirements stated in the OM Code.

Pressure Isolation Valves (PIVs)

Pressure Isolation Valves used as isolation valves from the Reactor Coolant Pressure Boundary have been identified as having various issues/concerns at several facilities. Some PIVs are either NOT included in the IST Program as PIVs and leak tested in accordance with requirements of the OM Code, or have been inadequately tested in the IST Program. Numerous industry/regulatory documents (e.g., ASME Interpretations, NUREG 1482, GL 89-04, etc.) have identified the PIV testing requirements, but some facilities are NOT even testing PIVs as power operated valves in the IST Program. Although some guidance was provided regarding testing of PIVs in GL 89-04, NUREG 1482 and other industry/regulatory documents, confusion still exists in the industry as to what valves should be included in the IST Program as PIVs and what testing should be required.

Power Operated Valves (ISTC-5100)

Many facilities continue to misinterpret the “acceptable stroke time” value and the “limiting value of full stroke time”, as stated in ISTC-5113 and ISTC-5114. The OM Code, OM-10, section 4.2.1.9 (b) and ISTC-5123, allow a “retest” and analysis to be performed if the acceptable range is exceeded, without declaring the valve inoperable. This allows the utility to have an “alternative” to declaring the valve inoperable if valve stroke time has changed slightly, thus preventing unnecessary entry into Limiting Conditions for Operation (LCOs) or requiring other actions which may or may not be providing an adequate corrective action or response to the problem or to the determination of valve degradation. The intent of this allowance to retest the valve and analyze later results is to provide the owner with a method of determining and monitoring degradation; thus assuring operational readiness of a component or, providing guidance as to how to determine and resolve other factors or changes that may have occurred to the component's condition or test method. This allows timely and adequate corrective action to be taken, without requiring more severe corrective action to be initiated until the extent of the condition is more clearly understood. Many times a valve stroke time is affected by either environmental or testing deviations rather than the valve actually being in a degraded or unacceptable condition. In other cases, the valve may be showing very early signs of degradation, that may not warrant an immediate or intrusive action to be taken. This is the purpose of allowing the valve to "analyzed" when the valve exceeds the acceptable range of the Code. This area of the Code used to be considered the "Alert Range" and required corrective action to be taken without allowing a determination of the actual cause of the deviation.

Additionally, many utilities still do not have a clear understanding of how to develop a reasonable "limiting value of full stroke time". The "limiting value of full stroke time" of a power operated valve in the IST Program continues to be required to be established as stated in OM-10, paragraph 4.2.1.4 (a) and ISTC-5113 (b), as applicable. The OM Code also requires a "limiting value of full stroke time" be developed for each power operated valve included in the IST Program. The purpose of establishing this "limiting value of full stroke time" and some additional general guidance for the establishment of the "limiting value of full stroke time" has been provided in NUREG 1482 and the NRC Workshop Summary, as well as other industry and regulatory documents.

The lack of understanding of "limiting value of full stroke time" and the "acceptable range" of a valve continue to be areas of concern which result in two issues or potential consequences. One consequence of this lack of clear understanding of these two terms could be unnecessary and potentially burdensome entry into LCOs, which could further result in unnecessary corrective actions being expedited. This could result in resources and costs being expended for unnecessary actions while more serious concerns may exist and, due to resource limitations, may go undetected. The other consequence of this lack of clear understanding of these two terms could be the failure to declare the valve inoperable and taking timely corrective actions as required by the OM Code in order to satisfy the intent of the IST Program.

Exercising Requirements (ISTC-3520)

Category C Check Valves are required to be bi-directionally tested in accordance with the requirements of ISTC-3522 and ISTC-5221. This has created numerous issues and concerns associated with exercising of check valves and has resulted in several facilities being in non-compliance with requirements of the OM Code. For several years, the industry has been trying to determine methods to provide assurance for check valve operational readiness without burdening the industry with unreasonable testing or acceptability requirements for assuring this condition. From a practical standpoint, bi-directional testing is not a new requirement. IWV and OM-10 have required verification of the valve disk going closed upon cessation or reversal of flow or going to its open position upon initiation of flow. These requirements, in essence, are the intent of "bi-directional" testing. The problems which have been identified with regards to bi-directional testing are lack of understanding of the term "test interval", lack of understanding of the "intent" of bi-directional testing, and continued lack of understanding of "full stroke open" for check valves (as clarified in GL 89-04, NUREG 1482, the NRC workshop summary, and later editions/addenda of the OM Code). In addition, many facilities have failed to adequately understand and implement the various non intrusive methods for determining the ability of the check valve to perform its safety function(s).

Significant efforts have been expended by the industry to address these issues and to provide more complete and comprehensive testing methods for determining actual condition of the check valve. The OM Code has understood the issues and concerns associated with performing testing on check valves in the IST Program and the limitations associated with these testing methods. The earlier Code requirements provided little insight into the intent of performing IST on check valves, and many failures were experienced without being previously detected under the IST Program, or allowing actions to be taken to prevent failure of the check valves. In reality, IST was providing little or no information as to "condition" of the check valve and was actually more of a "go or no-go" type of test. The industry and regulatory authorities have lately developed and endorsed a more acceptable and practical alternative to traditional testing methods incorporated into earlier editions of the Code. ASME has issued Appendix II as a mandatory appendix to the OM Code as referenced in ISTC-5222 to provide guidance and minimum requirements to be used in setting up a "condition monitoring program" for check valves. Benefits of this method are readily apparent, both from an IST perspective and a cost benefit perspective. The purpose of "condition monitoring" is to provide a more comprehensive evaluation of actual condition of the check valve and to establish more "realistic" test methods, requirements and acceptance criteria. This is beneficial in both the ability to ascertain condition of the check valve, and reducing unnecessary testing or monitoring requirements. This method of condition monitoring of check valves, when implemented correctly, will provide for a more accurate and true indication of the condition of the check valve while providing a reduction in cost for check valve testing in the IST Program.

As of this paper, several other components are being evaluated for “condition monitoring” type testing programs in the IST Program. These include AOVs, SOVs, pumps, etc. This will result in a more beneficial and complete evaluation of the condition of these components and the ability of the facility to more precisely and accurately ensure operational readiness of these components. Ultimately, this will result in improved safety and reliability at facilities and a more cost effective method for implementing IST.

Position Verification Testing (ISTC-3700)

Issues and concerns continue to be identified with regards to adequate verification of remote position indication required by the OM Code. Several facilities continue to not require position indication verification testing for solenoid valves, due to the fact that “stem movement is unable to be observed for many solenoid valves”. Since the 1970’s, remote valve position indication verification has been a requirement. Little has changed with regard to position indication verification of valves with the later editions of the Code. The primary change to the Code for position indication verification was in OM-10 when Table 1 was developed. Table 1 stated that remote valve position indication was required for active and passive valves. Unfortunately, a few utilities still do not perform position indication on passive valves in the IST Program. Primarily these valves have been manual valves with an identified passive safety function.

Another concern identified with regards to remote valve position indication verification is the lack of local observation of position indication verification being “supplemented by other indications such as flow, pressure, etc., where practicable or where local observation is not possible”, as required by the OM Code.

Industry and regulatory authorities have taken several steps to clarify remote valve position indication requirements as stated in the OM Code by providing additional guidance and direction in NUREG 1482, the NRC Workshop Summary, OM Code changes and interpretations, as well as other direct and indirect methods. However, it appears that many of these “clarifications” have either gone unheeded or mis-understood as evidenced by recent numerous findings associated with the Code requirements for remote valve position indication verification.

Manual Valves (ISTC-5210)

The lack of manual valves being included in IST Programs continues to be an issue in the industry. Many facilities have not included manual valves in their IST Programs due to a lack of understanding or bases of the safety function of the valve. Other facilities have failed to include exercise testing of manual valves which have active safety functions, as required by OM-10 and ISTC-3500.

In other instances, manual valves have had position indication verification performed, but have not had exercising performed, as required by the OM Code, even though the valves had been identified in the IST Program as active valves. This is also the result of clear lack of understanding of the safety function of the valve, a lack of understanding of the intent of the OM Code, or a combination of both.

Again, the industry and regulatory authorities have attempted to provide guidance and clarification regarding the IST requirements for manual valves in NUREG 1482, and the NRC Workshop Summary. There have also been several interpretations as well revisions to the OM Code, in an attempt to provide further clarification as to the testing requirements of manual valves.

It should be noted that occurrence of manual valve testing issues have decreased significantly since implementation of later editions of the Code. This may be a result of a better understanding of IST, and clarifications provided as described above. It needs to be noted here also, that frequency for manual valve exercising (at least once every 5 years) as stated in later editions of the OM Code (ISTC-3540) has had an exception taken to the test frequency by the NRC. As stated in 10 CFR 50.55a, the NRC requires a maximum of 2 years for the exercising frequency for manual valves, in lieu of the 5 years stated in the later OM Code (1998 edition thru the 2003 addenda).

Other Areas of Concern

Several other areas of concern continue to exist in the valve testing areas. Some of which cause facilities to fail to meet requirements of the OM Code. These include failure of utilities to stroke time or fail safe test control valves which have safety related functions, testing of check valves in parallel using a total flow determination method which does not adequately verify each check valve being able to open to its safety position, failure to stroke time power operated valves as required by OM-10 and ISTC which do not have remote position indication, failure to adequately perform a “fail-safe” test on power operated valves which do not have remote position indication, and failure to adequately perform remote position indication verification as required by ISTC and as clarified by various industry and regulatory documents. These are just a few issues/concerns identified and clarified several years ago and which continue to be identified as issues/concerns at plants using the later editions and addenda of the OM Code.

Pressure Relief Devices (Appendix I)

As with pumps and valves, a few of the more typical safety and relief valve issues/concerns identified in past IST program reviews and assessments have either been resolved, as a result of changes made to the OM Code, or have been so well identified and documented in various regulatory and industry documents published (i.e. NUREGS, INs, etc.) that the issues/concerns have been eliminated. However, unlike many previous pump and valve issues/concerns, many "old" issues for safety and relief valve testing in IST still remain. Some of the more recent changes and interpretations to the OM Code, Subsection ISTC and Appendix I, may provide clarification or additional guidance which could result in a few of these issues/concerns being eliminated in the near future.

Thermal Relief Devices (I-1200, I-1390)

One of the most common programmatic issues being identified at many facilities over the last few years has been "scoping" concerns associated with "thermal relief valves". Numerous attempts at providing clarification and guidance as to when and what safety and relief valves were required in the IST Program scope have been made over the last five or so years, with minimal success. Interpretations, NUREG 1482, and the NRC workshop summary provided the industry with guidance regarding inclusion of certain relief valves which did not directly affect safe shutdown of facilities during an accident, but could impact safe shutdown or accident mitigation functions of certain systems in the plant and were therefore considered important to safety. Many facilities attempted to "exclude" these safety and relief valves from IST Programs by using the justification of safety and relief valves not being specifically required to operate to perform a function that would require operational readiness determination by using IST. However, as numerous interpretations and regulatory/industry documents attempted to show, the valves could affect the ability of systems with which they were associated from being able to satisfy their safety function(s), even though the safety and relief valve itself may not be required to function at the time of the accident to mitigate consequences of an accident or maintain the safe shutdown condition of a facility. The concern was that the component the safety and relief valve was protecting (e.g., heat exchanger), as a result of the safety and relief valve failing to perform its safety function, could potentially cause the component/system to be unable to fulfill its safety function.

The later edition of the OM Code specifically defines a thermal relief device and provides testing guidance specifically related to this particular type of device. This should eliminate much of the confusion associated with "thermal relief valve" scoping concerns and ensure IST Programs include all applicable safety and relief valves. In addition, for class 2 and 3 thermal relief devices, testing frequency and methodology has been relaxed. In particular, "sampling" and the corrective action which requires the increase of the sampling population size have been essentially eliminated by the later Code, where an adequate determination of the cause of failure is provided. This is to ensure that a "generic failure" is identified if applicable, and the required corrective actions are appropriate to the failure mode of the safety or relief valve.

BWR Scram Accumulator Rupture Disks Exclusion (ISTC-1200)

Another major issue/concern identified previously, and essentially eliminated in the latest edition of the OM Code, is the requirement to test the BWR Scram Accumulator non-reclosing pressure relief devices (rupture disks) used in BWRs on the Scram Accumulators. Over the years several utilities tried to eliminate Scram Accumulator rupture disks using various "justifications". Some "justifications" included: de-classifying rupture disks, attempting to establish that rupture disks did not satisfy IST scoping criteria, attempting to exclude the rupture disks as "skid-mounted", etc. However, this Code change has not yet been approved by the regulator and therefore requires caution in use of this guidance.

Category A and B Safety and Relief Valves Excluded (ISTC-1200)

Since the early 1980's many facilities have had difficulty with testing safety and relief valves which had safety functions in both the Category A(B) as a power operated relief valve, and also was included in the Category C criteria as a safety and relief valve. This issue was a result of several facilities testing only one of the Categories for functionality and omitting the other Category of IST testing. Many facilities either eliminated the power operated valve testing or the relief valve testing component for some Category A and/or B valves in the IST Program. As stated in the Code if a valve has the characteristics of more than one category, then IST would be required to include testing to satisfy requirements of both categories, no duplication of testing being required.

For example, in some PWRs, facilities take credit for Power Operated Relief Valves (PORVs) for Low Temperature Over Pressure Protection (LTOP) and therefore the PORVs require testing as a power operated valve. However, PORVs typically have a stroke time on the order of 0.2 seconds and are pilot actuated. As a result, it is difficult, if not impossible, to stroke time PORVs as required by the Code. Also, due to the fact that PORVs normally do not have remote position indication and many problems/concerns have been identified with the testing methodology for PORVs, it was determined by the NRC via numerous relief requests and the ASME OM Code Committee that Code requirements for stroke timing PORVs and requiring position indication verification periodically was an undue burden with no increase in safety.

In addition, several PORVs also have a relief valve function to lift prior to the primary or pressurizer relief valves lifting. This is typically NOT a safety function at many facilities. As a result, the OM Code committee determined to provide an exemption to certain Category A and B safety and relief valves from certain IST requirements (stroke timing and position indication verification) in the later edition of the OM Code.

Set pressure Measurement Accuracy (I-1410)

Confusion has existed over required instrumentation accuracy. Many facilities did not or could not meet the previous tolerance for instrumentation stated in the Code. The later edition of the OM Code has provided specific instrumentation tolerance to be within 1% of the indicated (set pressure). This has resulted, for the most part, in elimination of issues/concerns associated with instrumentation tolerance for testing safety and relief valves in the IST Program.

Other issues/concerns continue to exist associated with the IST for safety and relief valves. Primarily, these issues/concerns are associated with test method, test media, and the associated requirements for providing a "correlation" and certified procedure documenting and addressing these different conditions of testing. Several clarifications and changes have been made to the OM Code which should eliminate much of the confusion associated with some of these requirements. Recent Code interpretations and future Code changes will eliminate others. Still others may be addressed by some future industry/regulatory documents which may further eliminate some of the more persistent issues/concerns. Below is a listing of the more typical issues/concerns associated with safety and relief valves and whether they have been addressed by changes to later Code editions or additional industry/regulatory guidance.

Ambient Temperature (I-1200)

Numerous facilities did NOT require safety and relief valves to be tested at ambient temperature, or provide a certified correlation as to the acceptability of testing certain safety and relief valves at other than ambient temperature when the valve would be required to perform its safety function, as required by the OM Code. The term "ambient temperature" has been defined in the later edition of the OM Code as "the temperature of the environment surrounding a pressure relief device at its installed plant location during the phase of plant operation for which the device is required for over pressure protection." This provides a clarification as to the definition of ambient temperature; however, questions still exist as to the use of ambient temperature when testing safety and relief valves. Several documents have been issued recently to provide clarification as to the testing of safety and relief valves in the IST Program which should alleviate most of the remaining concerns for safety and relief valve testing requirements.

Thermal Relief Application (I-1200)

As stated previously in this paper, numerous utilities do not include "thermal" safety and relief valves in IST Programs as required by the OM Code and clarified by numerous industry/regulatory documents. The term "thermal relief application" has been defined in the later edition of the OM Code as "a relief device whose only over pressure protection function is to protect isolated components, systems, or portions of systems from fluid expansion caused by changes in fluid temperature". This should help to clarify the scoping issues/concerns associated with safety and relief valves, in particular "thermal relief valves".

Safety and Relief Valve Acceptance Criteria (I-1320(c)(1))

Many facilities have NOT been in compliance with the OM Code regarding acceptable range of deviation allowed by the Code. In older editions of the Code typically a 3% band was required. Many utilities could not or did not satisfy the 3% band and provided a "technical position" as to the use of a larger tolerance. Later editions of the OM Code provide for the owner to establish a greater tolerance if justified. This could result in an additional issue associated with the "intent" of the Code regarding safety and relief valve testing not being met, but should provide a relaxation for set points which are "unrealistic" and unable to be met for which the NRC has granted similar relief in the past.

Set Pressure Testing (I-4000 and I-8000)

Numerous facilities have failed to satisfy the successful number of tests required by the OM Code. The OM Code has required two consecutive successful set point tests be performed for each safety and relief valves tested in the IST Program. Many facilities determined the safety and relief valve to be "successfully tested" upon satisfactory completion of the "as found" test. Other facilities were found to not have successfully completed two consecutive successful set point tests. Neither of these results satisfied the OM Code requirement of two consecutive successful set point tests. Although clarification has not been provided to address these specific issues/concerns in the later edition of the Code, the time between set point tests and the clarification of "as found" testing should serve as "pointers" or guidance which may provide some additional clarification.

Correlation/Certification of Safety and Relief Valve Testing (I-4000/I-8000)

Several issues/concerns have been identified with regard to correlation of differences in Code requirements/method of testing safety and relief valves and actual conditions/methods. If the test media, test temperature, etc., is different than the service media, temperature, etc., then, in many cases, a correlation has to be performed and documented and certified using a procedure. Many of the "required correlations" have been clarified, or in some cases eliminated, by recent changes to the OM Code. Changes to the Code which provide relaxation or alternatives to the Code testing requirements may serve to eliminate additional issues/concerns. One such example is the requirement to calculate accumulator capacity for test rigs used in testing safety and relief valves in the IST Program. The Code has now been revised to require the accumulator volume be "sufficient to determine the valve set-pressure".

Several Code changes and revisions have been made to enhance safety and relief valve testing requirements and provide clarification, both from the ASME OM Code Committee and the NRC. One major clarification made to the Appendix I requirement for testing relief valves is describing when the IST testing frequency is required to start. The OM Code in subsections I-1320 thru I-1360 states the test frequency for Class 1 safety and relief valves is 5 years and the test frequency for Class 2 and 3 safety and relief valves is 10 years. Concerns and questions have been raised regarding when the 5 or 10 year period starts? Does it require safety and relief valves be tested once every 5 or 10 years regardless of whether or not valves have been installed? Is the test frequency required to be maintained even if the safety and relief valves are "on the shelf"? The OM Code Committee recently provided an interpretation to the test frequency which should provide adequate clarification to the industry to provide for consistency and adequacy of implementation of the later Code requirements. The clarification provided the test frequency starts when "the safety and relief valves have been installed and are required to perform function" or, in other words when the valves have been "wetted". For example, if a Class 1 safety and relief valve was tested 3 years prior to installation at the facility, then the safety and relief valve would be required to be tested within 2 years after installation. This could create a problem with a plant that has a 24 month refueling or the refueling outage has been delayed which would cause the valve to exceed the 5 year frequency. Care needs to be taken prior to installing a safety and relief valve to ensure sufficient time exists to allow the valve to be tested within the test frequency specified in the OM Code, or actions have been taken to obtain approval of an extension of the safety and relief valve testing frequency as required, to ensure compliance with the requirements of the OM Code.

Test Frequencies, Class 1, 2 and 3 Pressure Relief Valves (I-1330 and I-1360)

Numerous issues/concerns have occurred regarding "sampling" of safety and relief valves and the requirements of the OM Code. The Code states that "...a minimum of 20% from each valve group shall be tested within any 24-month interval (Class 1, 48-month Class 2 and 3...). This 20% shall consist of valves that have not been tested during the current 5 (or 10) year interval, if they exist." Several utilities have used this statement to require safety and relief valves in that group only to be tested once every 5 or 10 years as applicable. These utilities erroneously believe that, upon completion of testing of the entire group, no relief valves would be required to be tested until the start of the next test interval. For example, a valve group consisting of four valves which are Class 3, and the Code requirements are met requiring 20% of the valves in this group to be tested on a 48 month interval (as a minimum). If the facility were to test all four valves in the group within the first 24 months, then it was erroneously determined that no other valves in the group were required to be tested until the start of the next ten year test interval. However, the Code would require the testing to start over, if previously untested valves were non-existent.

Some of the confusion caused by earlier Codes has been eliminated with issuance of the later Codes but, obviously, some confusion as to the intent of the Code requirement still exists at certain sites.

Another issue which has been raised regarding test frequency for safety and relief valves is, when maintenance is performed on one or more valves which affects the set point testing of the valve, can credit be taken for the post-maintenance test (PMT) of the safety and relief valve testing being performed as PMT or do the requirements of the Code regarding test frequency take precedence over the PMT performance? For example, when leakage is identified at a Main Steam Safety Valve and maintenance is performed on that valve to correct the leakage concern, can the PMT for that MSSV be substituted for the scheduled IST relief valve test if the valve was NOT scheduled to be tested during the upcoming refueling outage?

Clarification has been provided in NUREG 1482, the NRC Workshop Summary, and various interpretations and Code changes. This clarification requires essentially two tests to be conducted on the safety and relief valves in the IST Program in order to ensure compliance with the OM Code. One is to ensure that an "as found" test is performed on each safety and relief valve at least once every 5 or 10 years, as applicable. The second test requirement is to ensure that each safety and relief valve tested in the IST Program is "sampled" every 24 or 48 months as applicable to ensure any "generic" concerns are identified and adequate corrective action is taken in a timely manner.

Conclusion

There are many other issues/concerns which have been identified during recent assessments, or incidents at nuclear facilities. The ASME and the regulatory agencies as well as other industry support groups have contributed significantly to the reduction in occurrence of many of the earlier issues and concerns identified in the development, implementation and maintenance of IST Programs. These groups continue to strive to make IST a more reliable and cost effective method of determining operational readiness of safety related components used at nuclear power facilities. However, much continues to be needed to ensure the operational readiness of many components in the IST Program.

Several factors contribute to the continued instances of these issues/concerns including: lack of individual and management understanding of the intent of various subsections of the Code, "tribal knowledge", lack of management support of involvement of the facility in the various industry/regulatory initiatives involving IST, inconsistent/uncontrolled regulatory guidance at the facility level, etc. However, the major factor identified as a cause for this continued failure to implement Code requirements is significant turnover rate of IST Program Managers. This has been identified as an area of concern by both industry and regulatory agencies. For example on average, there is a change of 45-50% of IST personnel in the US nuclear industry every 2 to 3 years. This results in a significant loss of experience at many utilities and subsequently results in the utility's inability to maintain the much needed IST expertise at site. This many times results in junior level or inexperienced personnel being placed in the position of IST Program Manager with little or no understanding of IST. The OM Code committee and other industry initiatives being undertaken may help resolve the underlying cause for this issue and concern, and many facilities are now providing limited training for IST; however, the real challenge continues to be to provide sufficient clarification and guidance, both regulatory and within the industry, to ensure Code requirements are understood and the overall intent of the IST Program is adequately understood. This will ensure that the approved Code requirements are being satisfied and that IST Programs are being developed, implemented and maintained as required.

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The Future of ASME Nuclear Codes and Standards

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ABSTRACT

With the advent of the global marketplace, it is important that safety regulations continue to be met while government and industry promote international trade. ASME's Codes and Standards is taking steps to become a key international player. Current initiatives include promoting Codes and Standards in industry publications, simplifying access to ASME utilizing the Internet, participating in workshops and offering courses around the world. There is also an increased focus on international participation on Codes and Standards committees. This paper will discuss the goals of the ASME's Nuclear Codes and Standards Department pertaining to the expanded application of ASME Codes and Standards.

INTRODUCTION

As regional and global trade agreements such as the North American Free Trade Agreement (NAFTA), the European Union, and the World Trade Organization (WTO) are created; international boundaries have become less of a hindrance to trade. Companies are continually venturing into new territories in order to lower their costs and increase their market. It is important that safety is not compromised while trade is encouraged. ASME Codes and Standards (C&S), particularly Nuclear Codes and Standards (NCS) is looking towards the future and the need for consistency in safety and design standards.

The current Mission Statement of ASME C&S is "Develop the best, most widely applicable codes, standards and conformity assessment programs in the world for the benefit of humanity. Involve the best and brightest people from all around the world to develop, maintain and promote these ASME products and services world about." ASME's current consensus standards development embraces transparency and openness, impartiality and consensus, relevance, effectiveness and coherence. Future applicability of the standards is dependant on creating interest among these merging and emerging markets.

In the past, committees composed of members from mostly U.S. interests have developed ASME standards. In addition, and perhaps most detrimental to future global applicability, was the development of most standards sans metrication.

One of the keys to expansion is to make participation by international members as easy as possible. In order to increase international participation, the Council on Codes and Standards has proposed to revise current procedures. Changes would include a new level of membership where attendance at meetings was not essential. The responsibility of the international members would be to provide crucial input to the Committee based on their knowledge of the standard's application in their local area. An individual on the committee would act as the representative for a group of experts from a country. Application of the policy of participation would be on a case-by-case basis decided by the committees involved.

The use of Project Teams and the exchange of information via the Internet will make it more realistic to meld ideas across the globe and will reduce Standards development time.

Metrication has been a major undertaking by all ASME staff and volunteers over the past few years. Perhaps the greatest project, metricating the Boiler and Pressure Vessel Code is complete and will be published in July 2004. All Nuclear Codes and Standards are complete and published. Unlike previous attempts at metrication the 2004 Edition of the Boiler and Pressure Vessel Code will include a dual set of units – U.S. Customary and SI. A Code user may use either set of units for design and certification.

For almost five decades the nuclear power industry has been developing and improving reactor technology. Currently, the next two generations of reactors are being developed in several countries. The new reactors have simpler designs and are inherently safer and more fuel-efficient. ASME NCS is seizing an opportunity to aid in the standardization of design, material, quality assurance, risk technologies and eventual inservice inspection and testing requirements.

In the U.S. and abroad, new nuclear plant orders are expected before the end of the decade, with new construction beginning around 2010. It is a goal of NCS to be wholly involved and prepared when the activity begins. The main initiatives are to modify the present ASME Nuclear Codes and Standards as to be applicable to the new generation of reactors, to risk inform current codes and standards, and to evaluate methods to streamline acceptance of the standards in regulations. The Board on Nuclear Codes and Standards (BNCS), the body overseeing all NCS activities, has established a task group to address the new style reactors. This group will function as a manager for additions or changes to the present standards and will work with government officials and Nuclear Steam Supply System (NSSS) suppliers.

A dozen new reactor designs are at advanced stages of planning in Russia, South Africa, Europe, Japan and North America. The new reactors have a more rugged design to make them easier to operate reducing the possibility of core melt accidents. The designs will also have a longer operating life than the current plants, typically 60 years, while also minimizing the effect on the environment and amount of waste produced.

In the past few years, representatives of ASME NCS have been actively participating in events concerning new reactors. Most recently, the focus has been on four types: Pebble Bed Modular Reactors (PBMR), the Westinghouse AP-1000, the Advanced CANDU Light Water Reactor, and the International Reactor Innovative and Secure (IRIS). BNCS workshops on new reactors have been held with Westinghouse PBMR and Atomic Energy of Canada Limited (AECL). Other workshops are being planned for General Electric, General Atomics and Framatome ANP. In addition, BNCS representatives visited the PBMR Project demonstration in Centurion, Republic of South Africa.

Presentations focused on advantages of using ASME Standards, the planned initiatives of BNCS to better serve the needs of the new reactors and discussion of needs that are not met by the current standards.

A benefit of using ASME Standards is the reassurance that they have been promulgated using an open consensus process. This process prevents any one interest from unduly influencing Committee actions. To achieve consensus on an item, the Committee must consider all views and attempt to resolve all objections.

Basic needs for the new reactors can be put into four categories: quality assurance, materials, design, and inservice requirements. Beyond these, the needs are specific to the reactor type. Quality assurance requirements can be found in multiple standards including ASME's NQA-1, ISO 9000 and, locally, such as in Canada's CSA N286 series. Guidance needs to be created so minimum requirements will be met universally.

There is a great need for guidance on materials. Many materials that are not covered in current ASME standards will be used in the production of the new reactors, particularly the High Temperature Gas-Cooled Reactor (HTGR). Some of these materials will be included by expanding property information in current tables, such as high temperature stress strain curves, and including the effects of environment on materials (for example, oxygen and impurities in helium). Proprietary information and the limited number of experts in the use of graphite in nuclear applications may create difficulties in developing a consensus standard. Other non-metallic materials such as carbon-composites and ceramics must also be addressed.

Section III of the Boiler and Pressure Vessel Code "Rules for Construction of Nuclear Power Plant Components" is a good start to design but, as in the case of the CANDU Light Water Reactor, some design details are not addressed. For example, a rolled fitting is used in the CANDU design, but this detail is not included in Section III. Risk informed principles would also be essential in the design of the next generation reactors.

Inservice testing and inspection requirements need to be revisited. Longer operating cycles and components inside the reactor vessel make the current requirements difficult to apply to the new designs. Risk informed principles should also be used in the development of future ISI and IST requirements.

When information on the new generation of reactors is gathered from NSSS suppliers, assignments will be distributed to the appropriate Standards Committees to address the needs identified in the workshop.

The BNCS Task Group on Nuclear Risk Management is also working toward the consistency of Codes and Standards. ASME and the American Nuclear Society (ANS) are proposing a collaborated effort to form a Nuclear Risk Management Oversight Steering Committee. The committee's task would be to oversee standards activities associated with nuclear facilities. Members would be representatives of the U.S. Nuclear Regulatory Commission (USNRC), Department of Energy (DOE), and various other government agencies and standards development organizations, such as ASME, ANS and the Institute of Electronics and Electrical Engineers (IEEE).

Conclusion

By gathering experts in workshop type settings, identifying features that are not currently covered in NCS documents, and working on fixing these missing links, ASME NCS is laying the foundation for expanded application of its Codes and Standards to the next generation of nuclear reactors. Committees under NCS respond to the needs of the public and industry. Input from all stakeholders is always welcomed and encouraged.

If you would like to become involved in the committee or are just interested in gaining more information, the NCS webpages are located on the ASME website (www.asme.org) under Codes and Standards, C&S Committees.

MECHANICAL TESTING DEVICES – ARE THEY PATENTABLE?

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ABSTRACT

Intellectual Property (IP) rights exist in various forms that are useful to the field of valves and pumps. Intellectual property consists of patents, trademarks, copyrights, and trade secrets that are used to protect a variety of new methods of modeling strata, new equipment used in collecting data, and new software analyzing flow rates and capacities.

Today, building and maintaining an IP portfolio is simpler and less expensive than in years past. The first reason is due to a particular decision from the US Supreme Court that has become affectionately known as the Festo case which suggests inventors should not file one large patent, but numerous small ones. The second reason is because of a major legislative decision to provide for inexpensive "provisional patent applications." These "provisional patent applications" are useful in protecting ideas, methods, compositions, software, processes, and apparatus that are not yet completely tested or finished, yet protection is afforded to the "concept."

Intellectual Property (IP) is very similar to real property, in that it can be sold and licensed like real property. Intellectual Property can be used as (1) an asset, (2) a marketing tool, (3) a tool to protect market share, (4) a source of licensing income, and (5) a tool to enhance market share with customers.

The following paper will discuss how to identify what is protectable in the valve and pump industry with regard to testing and how to build a cost effective IP portfolio.

INTELLECTUAL PROPERTY AND MECHANICAL TESTING DEVICES

WHAT CAN BE PATENTED?

Patents enable the owner to have a monopoly on an idea, an apparatus, a method for manufacturing, a system, and/or a business method.

Patents can cover methods for analyzing data, software programs for compiling data, and devices and systems relevant to the pump industry. For an idea or an invention to be considered patentable, the invention must be (a) new, (b) useful, and (c) non-obvious to one "skilled in the art". The elements of "new" and "useful" are fairly straight. The "non-obvious" element has always been a challenge to explain.

Combinations of old elements when assembled in a new way with a new result, can lead to a patentable "non-obvious" idea.

Some patents issued by the United States Patent and Trademark Office (USPTO) in the testing area are listed as Attachment A. The following list includes abstracts from those patents in order to highlight the ideas that are currently being patented in the field:

1. 6,570,949 – METHOD AND APPARATUS FOR TESTING NUCLEAR REACTOR FUEL ASSEMBLIES: A method for testing whether fuel rods of fuel assemblies resting on a working base and under water, of a nuclear reactor are leaking is disclosed. The method includes heating at least one first fuel assembly of a first division of fuel assemblies for driving radioactive fission products out of a defective fuel rod contained in the first fuel assembly. The first fuel assembly is continuously tested by extracting samples of water and continuously degassing the water removed from an area around the first fuel assembly even during the heating resulting in gas. A radioactivity of gaseous fission products released in the gas is continuously recorded. A fuel assembly belonging to a second division of fuel assemblies is heated only if the first fuel assembly belonging to the first division of fuel assemblies has been tested. An apparatus for implementing the method is also disclosed.
2. 6,672,330 – VALVE BONDED WITH CORROSION AND WEAR PROOF ALLOY AND APPARATUSES USING SAID VALVE: A valve is characterized by excellent corrosion and wear resistance and

maintainability due to use of a bonding corrosion and wear proof alloy containing non-continuously distributed eutectic carbide on the sliding portions of various types of apparatuses and valves by diffusion bonding. This serves to improve the maintainability of a thermal and nuclear power plant and to provide a nuclear power plant using recirculating water, which ensures excellent working safety, in particular. The corrosion and wear proof alloy is characterized in that network-formed eutectic carbide in the alloy containing the cast structure base metal and eutectic carbide is formed into (multiple) granules or lumps having a particle size of 30 microns or less so that said eutectic carbide is non-continuously distributed.

3. 6,633,623 – APPARATUS AND METHODS FOR TESTING A JET PUMP NOZZLE ASSEMBLY AND INLET-MIXER: A jet pump for a nuclear reactor includes a riser and an inlet mixer having a set of nozzles and a mixing section for receiving coolant flow from the nozzles and suction flow from an annular space between the reactor vessel and the shroud core. To minimize or eliminate electrostatic deposition of charged particulates carried by the coolant on interior wall surface of the inlet-mixer of the jet pump, and also to inhibit stress corrosion cracking, the interior wall surfaces of the nozzles and mixing section are coated with a ceramic oxide such as TiO.sub.2 and Ta.sub.2 O.sub.5 to thicknesses of about 0.5-1.5 microns.

4. 6,526,114 – REMOTE AUTOMATED NUCLEAR REATOR JET PUMP DIFFUSER INSPECTION TOOL: An inspection apparatus for inspecting welds in a nuclear reactor jet pump includes a probe subassembly rotatably and linearly movably coupled to a frame structure configured to attach to a top flange of the reactor pressure vessel. The probe subassembly includes a plurality of probe arms pivotably coupled to a housing, with each probe arm including a sensor. The probe arms are pivotably movable between a first position where the probe arms are parallel to a longitudinal axis of the probe subassembly, and a second position where the probe arms are at an angle to the longitudinal axis of the probe subassembly. An insertion subassembly couples to the jet pump suction inlet. The insertion subassembly is sized to receive the probe subassembly and guide the probe subassembly into the jet pump through the jet pump suction inlet.

Some of the cases on the list relate to systems usable for testing in nuclear reactors. See Attachment B for an example of an apparatus (device) patent claims section of a system called Device for Materials Testing in Nuclear Reactors, noted as U.S. Patent 5,369,677.

Some system cases exist that are assemblages of known apparatus forming a system that has a new, useful, and non-obvious feature.

In short, patents can be issued for:

1. Methods for doing something;
2. Software programs;
3. Methods of doing business;
4. Systems, which are assemblages of old known components which now do something new; and
5. Apparatus, such as a new type of testing device for valves and/or pumps.

TYPE OF PATENT FILINGS – PROVISIONAL AND UTILITY FILINGS

Several of the cases described above are utility filings based on more limited "provisional" application filings. The scope of patent law in the United States has changed to allow inventors to file a less complete patent application than in the past to protect their ideas. These new cases are called "provisional patent applications". Generally, provisional patents are used for inventions that are not yet finished or not completely tested. The provisional filing allows the inventor to include additional subject matter or modifications to the original ideas within a 12-months period and still have the benefit of the first filing date of the case.

Facing steep competition, manufacturers are attempting to differentiate their technology in ways that are simply more than "new and improved" without excessive legal fees. Filing a provisional patent application enables a developer to obtain a federal filing date, effectively preserving the date of the invention plus rights in 121 other countries, so that further development can occur, while having some pending protection in place, reducing the need for secrecy and non-disclosure agreements for the idea.

By filing the idea with the United States Patent Office first, many developers find that disputes over ownership of the idea can be avoided.

One example of a company that is now "filing first" and asking questions later is Microsoft. Last year alone, Microsoft has filed 250 times more patent application than it owned twelve years ago. Microsoft recognizes that ideas are:

1. assets;
2. marketing tools;
3. sources of licensing income; and
4. tools for protecting market share.

What does a typical patent protection cost?

Four to six provisional patent applications can be purchased for approximately $26,000 USD. Typically, the cost for a patent dispute is about $600,000 USD in attorney fees.

Does having a few filings avoid a dispute? Maybe.

The traditional patent application is know as a utility patent. Design patents exist for ornamental designs, and plant patents exist for roses and other plants. A utility patent is typically protecting an invention for twenty (20) years from the filing date of the application.

The granted patent monopoly is a right to exclude others from making, using, selling, or importing into the United States, the system, method, or compositions that are "claimed" in the issued patent.

During the first 12 months of a pending provisional or utility patent application case, "no-cost" corresponding pending patent rights exist in more than 121 foreign countries.

All U.S. patent applications must be filed within one year of the first offer for sale or the first commercial use or demonstration of the invention. If the application is not filed within that year, the patent filing will be deemed fraud on the patent office.

Patents are obtained through a lengthy, multi-year process, usually about three (3) years. Generally, numerous steps are involved when obtaining a United States patent. Attachment C of this paper provides a general timeline of this process.

A tremendous amount of detail on this topic can be read at United States Patent and Trademark Office website at www.USPTO.gov.

Copyrights

Unlike Patents that protect an idea, Copyrights protect an original expression as fixed in a tangible medium. Drawings, plans and specifications are all potentially copyrightable if the drawing or plan is in a tangible medium. Legal protection happens instantly when the original copyrightable subject matter is fixed in a tangible medium, such as a digital form.

Beyond the congressionally created legal protection that attaches once the subject matter is in a tangible medium, an author or creator can obtain further rights and remedies by paying $30 USD to the government and filing the proper paperwork at Library of Congress' website, see www.loc.gov for more details.

By simply registering the copyrightable subject matter (i.e. a writing, a drawing, a picture, or a plan) with the Library of Congress and paying the required fee, three (3) additional rights are obtained to protect the subject matter in the event another uses the work without consent:

1. One to five years (1-5) in jail, if an infringer makes more than 10 copies of the registered work in 180 days and the aggregate value exceeds $2500 USD;
2. A minimum statutory damage of $25,000 USD if an infringer makes copies of the registered work, even if the copies are distributed free; and
3. Reimbursement of attorney fees incurred by the owner of the copyright in enforcing the copyright.

Trade Secrets

Yet another type of Intellectual Property is trade secrets. Trade secrets are defined as secrets that give a business a competitive advantage over another. In general, these secrets can include techniques, formulations, and business methods to obtain new business.

Trade secrets can protect any technical or business information that has a potential economic value and is a secret. Reasonable efforts must be made to keep the information secret. An example of a reasonable effort is the use of a Non-Disclosure Agreement (NDA) or a "Secrecy" Agreement. An example of a Secrecy" Agreement is shown in Attachment E.

Each non-disclosure or "secrecy" agreement needs to have at least the following three (3) critical elements:

1. A statement about the scope of the agreement;
2. A statement about the term of nondisclosure (i.e., 5 years, 10 years, or another time period); and
3. A statement regarding non-use of the subject to be disclosed.

If an inventor is receiving information, then the secrecy agreement should have a shorter term and a narrower scope. If an inventor is giving information to a third party, then the agreement should include a longer term and wider scope.

In order to maintain trade secrets, no formal filing procedure to register trade secrets is required.

Trademarks

Finally, a trademark is any word, name, symbol, or device that identifies goods of one company and distinguishes them from goods of another. Trademarks for nuclear engineers can include a company name, such as Mission Valve and Pump.

Other types of trademarks include:

1. Symbols or logos, such as a special arrow that is affiliated with a service like surveying by a particular pump manufacturer;
2. Slogans, such "We know how to check that flow";
3. Colors or color combinations, such as the royal blue for all valves produced by a particular business;
4. Sounds of a pump; and
5. Smells.

Trademarks can be registered on a Federal basis with the United States Patent and Trademark Office. Trademarks can also be filed in a given State with the Secretary of State. Trademarks can be filed both on a federal and state level.

Common law trademarks also exist.

Trademarks must be filed describing a particular good or service using a non-generic and non-descriptive term. A unique trademark filed at the USPTO is then registered on the Primary Register. However, if the mark is either descriptive or generic, the mark can still obtain a federal filing on the Supplemental Register.

Trademarks afford legal protection for the good will associated with the use of the recognized name, symbol, slogan, color, sound, or smell in relation to a good (product) or service.

Trademarks provide exclusive rights within the United States. As long as a trademark is used commercially, it can be renewed.

CONCLUSION

If inventions are not properly protected, the invention can fall into the public domain and may be used by any party without a license or payment. A sound patent, trademark, copyright and trade secret (collectively IP) management strategy involves systematically building an IP portfolio, consisting of different IP rights that cover various aspects of a company's technology and commercial interests.

Most companies protect their company name and major products or services with trademarks. Clever companies protect ideas with one or more patents. Low risk companies protect one or more of their trade secrets with secrecy agreements with third parties, employees, contractors, and even vendors.

Software companies and designers of models typically protect software with copyrights after those ideas are first evaluated for qualification for patent protection.

ATTACHMENT A

6,577,128	NQR method and apparatus for testing a sample by applying multiple excitation blocks with different delay times
6,570,949	Method and apparatus for testing nuclear reactor fuel assemblies
6,566,873	Method of and apparatus for nuclear quadrupole resonance testing a sample
6,486,838	Apparatus for and method of Nuclear Quadrupole Resonance testing a sample
6,459,748	Floating ultrasonic testing end effector for a robotic arm
6,404,835	Nuclear reactor rod drop time testing method
6,222,364	Method of nuclear quadrupole resonance testing and method of configuring apparatus for nuclear quadrupole resonance testing
6,208,136	Method of and apparatus for nuclear quadrupole resonance testing a sample, and pulse sequence for exciting nuclear quadrupole resonance
6,166,541	Apparatus for and method of nuclear quadrupole resonance testing of a sample
6,127,824	Nuclear quadrupole resonance testing
6,111,409	Nuclear magnetic reasonance fluid characterization apparatus and method for using with electric wireline formation testing instruments
6,100,688	Methods and apparatus for NQR testing
6,091,240	Method of nuclear quadrupole resonance testing and method of configuring apparatus for nuclear quadrupole resonance testing
6,088,423	Multiview x-ray based system for detecting contraband such as in baggage
5,958,710	Orphan receptor
5,946,364	Densification test procedure for urania
5,875,406	Method for reducing radioactive waste, particularly oils and solvents
5,841,824	System and method for testing the free fall time of nuclear reactor control rods
5,814,989	Methods and apparatus for NQR testing
5,814,987	Apparatus for and method of nuclear resonance testing
5,786,691	Detection of thermal damage in composite materials using low field nuclear magnetc resonance testing
5,754,610	In-mast sipping modular mast modification
5,717,731	Outage cover for nuclear reactor containment vessel
5,651,334	Steam generator lateral support
5,621,209	Attomole detector
5,591,974	Automated collection and processing of environmental samples
5,544,208	Method and apparatus for in situ detection of defective nuclear fuel assembly
5,504,881	Method for testing and validating the primitives of a real-time executive by activating cooperating task using these primitives
5,491,414	Method of nuclear quadrupole resonance testing of integral spin quantum number systems
5,490,443	Pressure-discharged type retaining system
5,459,767	Method for testing the strength and structural integrity of nuclear fuel particles
5,438,862	System and method for in situ testing of the leak-tightness of a tubular member
5,428,653	Apparatus and method for nuclear power and propulsion
5,377,234	Colloidal resin slurry recycle concentrating system of nuclear reactor coolant water
5,369,677	Device for materials testing in nuclear reactors
5,369,362	Method of and apparatus for NMR testing
5,347,553	Method of installing a control room console in a nuclear power plant
5,304,919	Electronic constant current and current pulse signal generator for nuclear instrumentation testing

5,289,875	Apparatus for obtaining subterranean fluid samples
5,287,390	Alarm system for a nuclear control complex
5,271,046	Manipulator and process for carrying out work in the connection-piece region of a vessel, in particular non-destructive testing
5,271,045	Advanced nuclear plant control complex
5,267,278	Console for a nuclear control complex
5,267,277	Indicator system for advanced nuclear plant control complex
5,265,131	Indicator system for a process plant control complex
5,227,122	Display device for indicating the value of a parameter in a process plant
5,227,121	Advanced nuclear plant control room complex
5,223,207	Expert system for online surveillance of nuclear reactor coolant pumps
5,215,706	Method and apparatus for ultrasonic testing of nuclear fuel rods employing an alignment guide
5,208,165	Method for testing the soluble contents of nuclear reactor coolant water
5,182,955	Borehole formation model for testing nuclear logging instruments
5,151,244	Apparatus for filtering and adjusting the pH of nuclear reactor coolant water for the testing of soluble contents therefor
5,137,086	Method and apparatus for obtaining subterranean fluid samples
5,128,094	Test instrument manipulation for nuclear reactor pressure vessel
5,118,462	Manipulator for handling operations, particularly for non-destructive testing
5,108,692	Non-destructive testing of nuclear fuel rods
5,097,199	Voltage controlled current source
5,095,753	Device for ultrasonic testing of a head screw inserted into a component
5,072,732	NMR instrument for testing for fluid constituents
5,065,097	Testing method and apparatus by use of NMR
5,025,215	Support equipment for a combination eddy current and ultrasonic testing probe for inspection of steam generator tubing
5,009,835	Nuclear fuel rod helium leak inspection apparatus and method
5,008,906	Consistency measuring device for a slurry containing defoamer
4,902,467	Non-destructive testing of nuclear fuel rods
4,875,486	Instrument and method for non-invasive in vivo testing for body fluid constituents
4,866,385	Consistency measuring device
4,851,183	Underground nuclear power station using self-regulating heat-pipe controlled reactors
4,799,305	Tube protection device
4,770,029	Valve testing method and device
4,735,766	Method and apparatus for testing vertically extending fuel rods of water-cooled nuclear reactors which are combined in a fuel rod cluster
4,728,482	Method for internal inspection of a pressurized water nuclear reactor pressure vessel
4,720,422	Material for collecting radionuclides and heavy metals
4,699,753	Reactor refueling machine simulator
4,689,193	Mechanism for testing fuel tubes in nuclear fuel bundles
4,687,992	Method for testing parts, especially of nuclear plants, by means of eddy current
4,652,418	Plug testing and removal tool
4,643,866	Nuclear fuel pellet-cladding interaction test device and method modeling in-core reactor thermal conditions
4,643,029	Ultrasonic probe for the remote inspection of nuclear reactor vessel nozzles
4,642,215	Universal tool for ultrasonic testing of nuclear reactor vessels
4,640,812	Nuclear system test simulator

4,636,645	Closure system for a spent fuel storage cask
4,623,294	Apparatus for carrying out repair, maintenance or testing of apparatus, components and the like in hot cells
4,608,991	Method for in-vivo NMR measurements in the human breast to screen for small breast cancer in an otherwise healthy breast
4,590,472	Analog signal conditioner for thermal coupled signals
4,587,077	Safety actuator release device
4,564,422	Method and apparatus for detection of erosive cavitation in an aqueous solution
4,554,128	Nuclear fuel rod end plug weld inspection
4,526,311	Method for carrying out repair, maintenance or testing apparatus, components and the like in hot cells
4,519,090	Testable time delay
4,518,822	Method and apparatus for automatically establishing telephone communication links
4,517,154	Self-test subsystem for nuclear reactor protection system
4,513,205	Inner and outer waste storage vaults with leak-testing accessibility
4,499,375	Nuclear imaging phantom
4,461,996	Nuclear magnetic resonance cell having improved temperature sensitivity and method for manufacturing same
4,460,920	Automatically traveling tube-interior manipulator for remotely controlled transportation of testing devices and tools along given feedpaths, preferably for nuclear reactor installations
4,460,832	Attenuator for providing a test image from a radiation source
4,453,501	Transducer for determining if steam generator tubes are locked in at support plate
4,452,250	NMR System for the non-invasive study of phosphorus metabilism
4,446,099	Device for protecting control cluster actuating mechanisms during the testing of a nuclear reactor
4,428,236	Method of acoustic emission testing of steel vessels or pipelines, especially for nuclear reactor installations
4,416,846	Nuclear power plant with cooling circuit
4,416,409	Method for manufacturing a metal casing for gate valves used in nuclear reactors and the like
4,415,771	Public alert and advisory systems
4,402,904	Method for determining clad integrity of a nuclear fuel rod
4,395,380	Method of testing fluid flow condition in extension of a pipe
4,384,489	Method of monitoring stored nuclear fuel elements
4,368,580	Apparatus for testing the diameter of a cylindrical hole machined in a very thick part
4,366,711	Method of testing fuel rods for assemblies for nuclear reactors and corresponding apparatus
4,351,824	Polystyrene latex reagents, methods of preparation, and use in immunological procedures
4,324,616	Detachable and leaktight device for closing an orifice of a nuclear reactor vessel
4,319,736	Apparatus and method for manufacturing a metal casing particularly for gate valves used in nuclear reactors and the like, having a large nominal width and a casing manufactured in accordance with the method
4,296,378	Apparatus providing enhanced detection of specimens in inhomogeneous fields
4,292,129	Monitoring of operating processes
4,248,666	Method of detecting leakage of radioactive gas from a nuclear fuel assembly
4,192,173	Eccentric pin mounting system
4,172,760	Neutron transmission testing apparatus and method
4,131,018	Elbow or bent tube manipulator, especially for ultrasonic testing in nuclear reactor installation
4,117,733	Test system carrier for ultrasonic testing of nozzle seams, pipe connection seams and nozzle corners in pressure vessels, particularly reactor pressure vessels of nuclear power plants
4,096,032	Modular in-core flow filter for a nuclear reactor
4,092,217	Fuel elements for nuclear reactors and method for testing the circulation of fuel elements in a core of a nuclear reactor
4,087,323	Pipe connector

4,073,665	Microwatt thermoelectric generator
4,072,559	Method and apparatus for the zone-wise shuffling of nuclear reactor fuel elements
4,067,771	Nuclear reactor containment spray testing system
4,034,599	Device for locating defective fuel
3,996,465	Test rig for subjecting specimens to high temperature behavior tests
3,984,258	Microwatt thermoelectric generator
3,980,503	Microwatt thermoelectric generator
3,980,502	Microwatt thermoelectric generator
3,951,692	Microwatt thermoelectric generator
3,940,311	Nuclear reactor internals construction and failed fuel rod detection system

ATTACHMENT “B”

Device for materials testing in nuclear reactors – Patent No. 5,369,677

1. A device for load-testing of specimens (3) in a nuclear reactor environment, characterized in that at one of the pipes (1) of the nuclear reactor for conveying a first medium under pressure, there is fixed a testing device (2) comprising a first space (14) in open communication with said pipe (1), a movable pull rod (15) arranged in said first space (14), one end of said pull rod (15) being intended to be attached to one half (16) of a specimen (3) arranged in the space (14), the other end of said pull rod (15) being joined to a tensile force device, capable of being influenced by the first medium, for achieving a tensile stress in the specimen (3) via the pull rod (15).

2. A device according to claim 1, characterized in that the testing device (2) comprises a first sleeve (13, 6, 8), connected to the pipe (1) in open communication, and an extension, which is movable in relation to the first sleeve, in the form of a second sleeve (9), said sleeves together surrounding at least part of said first space (14), a pull rod (15) arranged in said first space (14) with one end fixed to the movable second sleeve (9), the other end of the pull rod (15) being adapted to be attached to one half (16) of a specimen (3) fixed in the space (14), said second sleeve (9) being adapted to be influenced by a first medium supplied from the pipe (1) in order to achieve a tensile stress in the specimen (3) via the pull rod (15).

3. A device according to claim 2, characterized in that the first and second sleeves are interconnected by means of a bellows (10), said second sleeve (9) and bellows (10) being surrounded by a third sleeve (11) forming a second space (12) around said second sleeve (9) and the bellows (10), said second sleeve (12) containing or being connectable to a second medium of lower pressure than said first medium.

4. A device according to claim 3, characterized in that said second space (12) is also connectable to a medium of the same or a higher pressure in relation to said first medium.

5. A device according to claim 1 or 2, characterized in that several specimens (3) are connected in series in said first space (54).

6. A device according to claim 1 or 2, characterized in that the testing device (2, 42) is detachably attached to said pipe (1, 41).

Attachment C

Utility Patent Timeline*

	Event	Time
1.	Optional Patentability Search ⬇	3-6 weeks
2.	Optional provisional patent application filed ⬇	3-4 weeks to draft and obtain filing date at U.S. Patent & Trademark Office ("USPTO")
3.	Provisional application sits while applicant develops and tests invention ⬇	11 months from filing date from USPTO
4.	Conversion of Provisional to Utility application ⬇	1 month process to add additional claims and subject matter from testing and to improve figures if used in case
5.	Filing as Utility Application ⬇	
6.	Obtain Filing Receipt ⬇	60-90 days from filing
7.	Receive first rejection from USPTO ⬇	9-16 months from utility filing date
8.	Draft and file Response to 1st Rejection or Draft Response and interview case ⬇	Within 30-60 days of date of Notice of Rejection
9.	Receive 2nd Rejection ⬇	9-16 months from filing of Response to 1st Rejection
10.	Draft and file Response to 2nd Rejection ⬇	Within 30-60 days of date of notice of 2nd Rejection

11.	A. Call Examiner or B. Appeal or C. Receive Notice of Allowance ⬇	Within 140 days from 2nd Rejection Within 180 days from 2nd Rejection, if a final rejection Within 6 months
12.	Prepare formal drawings, advise client of costs of Issue Fee, formal drawings and attorney's fees for completion of work ⬇	Upon receipt of Notice of Allowance and Issue Fee Due
13.	Sent Issue Fee documents with Issue fee and formal drawings, if required, to PTO ⬇	Within 3 months from date of Notice of Allowance and Issue Fee Due
14.	Consider filing Divisionals, Continuations on additional improved subject matter to use same priority date for seamless monopoly ⬇	Within 3 months from date of Notice of Allowance and Issue Fee Due
15.	**Patent Issues**	
16.	3.5 year Maintenance Fee ⬇	
17.	7.5 year Maintenance Fee ⬇	
18.	11.5 year Maintenance Fee	

*This is a typical timeline. Times may vary on a case-by-case basis. There is no guarantee any patent application will issue as a patent.

ATTACHMENT D

CONFIDENTIALITY AGREEMENT

This Agreement, effective this ___ day of _______ , ________ is by and between ________________________., having an address at _________________________ (hereinafter referred to as "__________"), and ______________________________ ____, having an address at ______________________ (hereinafter referred to as "______________").

WHEREAS, the Parties are interested in discussing information relating to ________________ and various proprietary methods for doing business as __________________ and the asset acquisition of certain assets, financials and trade secrets of ________________ (hereinafter "Method for ___________________and the assets, financials and trade secrets of _________ _______ "); and

WHEREAS such discussions may involve the disclosure by ________________ of technical and/or business information which ________________ considers confidential, proprietary and valuable relative to Method __________________as well as the assets, financials and trade secrets of ________________ ;

NOW, THEREFORE, ________________ is willing to disclose such information on Methods __________________and the assets, financials and trade secrets of ________________ only under the following terms and conditions:

1. "________________ Confidential Information" shall be defined to include any information disclosed to ______________ ____ either through disclosures by ________________ representatives and/or affiliates or by third parties on behalf of ___ _____________ or such affiliates (collectively "________________ "), either directly or indirectly, in writings, drawings, photographs, samples, demonstrations or by inspection of plants or other facilities or in any other way and may include any analysis information provided to __________________ or obtained by __________________ on Method ______________ ____and information on the assets, financials and trade secrets of ________________ .

   ________________ Confidential Information shall not apply to information which __________________ can show was:

   (a) in the public knowledge or in the literature at the time of disclosure by ________________ ; or

   (b) already in __________________'s possession, in written form, at the time of disclosure by ______________ without obligation of confidentiality.

   Specific disclosures made hereunder shall not be deemed to be within the above exceptions merely because they are embraced by general disclosures in the public knowledge or literature or in __________________'s possession, and any combination of features disclosed hereunder shall not be deemed within the above exceptions merely because individual features are in the public knowledge or in __________________'s possession.

2. The purpose of disclosure of ________________ Confidential Information to __________________ under this Agreement is to enable __________________ to understand and talk about Method __________________and the assets, financials and trade secrets of ________________ with ________________ and only with ________________ .

3. __________________ agrees not to disclose ________________ Confidential Information received hereunder to any third party and not to use the same, except for the purpose noted above.

4. __________________ agrees to restrict disclosure and treatment of ________________ Confidential Information to only those employees who have a need to know such information to carry out the purposes of this Agreement. ______________ ____ agrees to handle and safeguard ________________ Confidential Information in the same manner as _____________ _____ handles and safeguards its own proprietary information of similar nature.

5. __________________ agrees that it will not make copies or excerpts of ________________ Confidential Information without ________________'s prior written permission and agrees that it will, upon request therefor, return to ___________ _____ any and all such ________________ Confidential Information which is in writing or other tangible form and which is in __________________'s possession or control, including any and all excerpts and copies thereof. All documents, drawings, samples and writings provided to __________________ hereunder and any copies thereof shall be returned promptly to ________________ upon the conclusion of the discussions of this project, unless sooner requested by _______ _________ .

6. This Agreement does not grant and shall not be construed as granting to __________________ a license or any rights under any of ________________'s patent, trademark, copyright or trade secret, or other intellectual property rights except as expressly noted herein.

7. __________________ represents that its officers, employees, and the like who may have access to ________________ Confidential Information are legally obligated to preserve the confidentiality of such information.

8. __________________ agrees to assign and hereby assigns to ________________ any improvement, invention, work of authorship, mask work, idea or know-how (whether or not patentable) that is conceived, learned or reduced to practice under this Agreement, or through discussions with third parties, and any patent rights, copyrights, trade secret rights, mask work rights and other rights with respect thereto. __________________ agrees to take any action reasonably requested by ________________ to evidence, perfect, obtain, maintain, enforce or defend the foregoing.

9. Except as may be otherwise permitted by this Agreement, the __________________ shall not copy, duplicate, reverse engineer, reverse compile, disassemble, record, or otherwise reproduce any part of Confidential Information, nor attempt to do any of the foregoing, without the prior written consent of the ________________ . Any tangible embodiments of Confidential Information that may be generated by a __________________, either pursuant to or in violation of this Agreement, will be deemed to the sole property of the ________________ and fully subject to the obligation of confidence set forth in this Section.

Accepted and Agreed:

By:________________________________	By:____
Printed Name: _______________________	Printed Name: ______________________________
Title:______________________________	Title: _____________________________________
Date:______________________________	Date: _____________________________________

Qualifying Active Valves for use in Nuclear Power Plants A new Revision to ASME QME-1 Section QV

Thomas Ruggiero, PE
Chairman of ASME QME

The views and opinions presented herein are my own as an engineer and not as Chairman of the American Society of Mechanical Engineers (ASME) Committee on Qualification of Mechanical Equipment Used in Nuclear Facilities (QME). They are not to be construed as the views of ASME, my employer nor of the U.S. Nuclear Regulatory Commission (NRC). The information presented herein may or may not be in the final revised Section QV, "Functional Qualification Requirements for Active Valve Assemblies for Nuclear Power Plants," in ASME QME-1 "Qualification of Active Mechanical Equipment used in Nuclear Power Plants," when it is published. What is published in QME and QV will be the result of ASME's review and ballot procedures and processes.

QME, History of Development

In 1974, NRC issued Regulatory Guide 1.48 which described the qualification of Active Pumps and Valves in Nuclear Power Plants and specifically noted that testing was the preferred method. ASME *Boiler & Pressure Vessel Code* (B&PV) Section III includes rules for the design and testing to ensure integrity of the pressure boundary. However, the Boiler Code did not and does not include qualification of function. The definition of Active, in those days, was basically any Nuclear Safety Related Component that was required to function in order to safely shut down the Nuclear Reactor.

The ANSI N45 committee was in existence prior to the issuance of the Regulatory Guide. The committee was tasked with developing qualification standards. The Committee established two Task Groups to develop qualification standards. These standards were for Pumps and for Valves. In 1974, the Valve Task force (N278) was reassigned to the American National Standards Committee B16 and was designated Subcommittee H.

The first Qualification Standard to be issued was ANSI N278.1-1975. This standard provided the requirements for the preparation of a functional specification by the user to provide information to the manufacturer on the design and operating requirements for an Active Valve, its Actuator and all Appurtenances. Also, in the early 1980s, an MSS (Manufacturers Standardization Society of the Valve Industry) standard was issued and then ANSI B16.41 specifically addressed qualification of Valve Assemblies.

In 1982, the Subcommittee H was again reassigned, this time to its present home, ASME Committee on Qualification of Mechanical Equipment Used in Nuclear Power Plants. This is when the two task groups (Pumps and Valves) were once again united under the same committee.

The Present QME and some Major Differences in Rules for Pumps versus Valves

When the valve group and pump group moved into different committees in 1974, they proceeded down decidedly different paths. Pumps, by their very nature, had always had some sort of performance test in the manufacturer's facility. Everyone is familiar with the shop generated head flow characteristic curve. These tests generally were specified by the owner and the tests were, and are, generally those described by Hydraulic Institute. Valves, except safety/relief valves and control valves, had no such test. Also, in many cases, performance for typical gate and globe valves simply wasn't specified. Generally, the typical valve specification asked for a certain ANSI rating, a type, a material, how it was to be connected into the pipe and, if it had a motor actuator, maybe the design pressure differential across the valve. Generally, except for Main Steam and Feedwater Isolation Valves, the flow rate was never specified much less an accident flow rate due to a postulated pipe rupture.

The Pump Group developed a standard that provided general guidance on what qualification parameters needed to be proven for a pump that was to be an Active Component. This was aided by the fact that Functional testing was not new for pumps; that manufacturers were very used to the idea of specifying nozzle loads on their equipment; and that Architect Engineering Firms were used to the idea of checking pipe generated loads on pumps (a pump is typically an anchor point in a Stress Analysis). Also, there was never any thought of a pump being required to operate if its discharge pipe had a rupture (in that case you specifically do not want it to operate). Hence, there was no need to even think of rupture loads on pump nozzles. The only new wrinkle was Seismic Qualification and that was typically handled through the use of IEEE 344.

With valves, it was significantly more complicated. For one thing, there are many more of them. Second, they are not typically flow tested. Third, some of them are required to isolate a postulated full guillotine rupture and, last but not least, the piping designer never checked the end loads on a valve that was not an anchor. All of these things conspired into a standard that was extremely prescriptive.

The Parents of Section QV and QV as It Is Now

The present QV is, for the most part, based on a standard that was developed in the mid to late 1970s. At that time, it was thought that many new Nuclear Power Plants would be built and that a valve manufacturer would qualify much of the line of products; in effect giving those products the equivalent of an "N" stamp for qualification. There was no thought whatsoever of requiring end loads to be limited. One reason being that the valve was in-line mounted in a piping system and it was very difficult to calculate actual valve end loads transmitted from the pipe if the valve wasn't near a support. It was realized that flow testing was expensive, but you can spread these costs over the several valve sizes that met a set of similarity rules (the parent/candidate valve assembly concept). The present Qualification requirements in QV generally are those that were provided in 1978. What delayed the issuance of B16.41 frankly had little to do with the tests themselves. The delay was primarily caused by rules to allow similarity because a valve that went through the whole test series probably had to be a prototype since the testing likely significantly damaged it.

The group concept was, in the most part, required because valve testing was incredibly expensive. Indeed, it was also not far fetched that in some instances a user who needed two valves might have to buy a third test valve to throw away. Also, it might also be that a user may have to buy a test fixture for the valve and hope that the valve passes. Prototype testing to destruction is common in the auto industry and aerospace where you are making thousands of exact copies. While this might have been acceptable when many thousands of valves were procured, it is extremely prohibitive when only a dozen are procured in a year.

Experiences with the Present QV

Since QME was developed, there has been little new construction domestically. The Standard has been used very sparingly, if at all. Where QV has been used there have been interpretation problems. Judging by the Inquiries that we have received as well as comments from testing labs and valve manufacturers, several concerns became apparent.

First, in many instances the user community was not providing the required functional specification. Simply, they specified to the manufacturer, within the typical procurement type specification, that valves needed to be qualified to either B16.41 or to QME with no delineation of what parameters needed to be ensured what actual design and operating conditions were and what was the acceptance criterion.

Second, we have received comments from testing labs that certain tests (specifically for check valves) were very difficult to perform at best, and very dangerous to perform at worst.

Third, the testing is extremely expensive and, in many cases, cannot be performed with facilities that are available.

Fourth, the scope of those valves to be qualified is well beyond the limited scope of "active" components.

Fifth, many of us on the subcommittee recognize that technology allows many more options than those available when the original concept of valve qualification was envisioned over thirty years ago.

Finally, there have been inquiries that we have discussed and had to say, "Yes that is what it says"; while within the committee we wonder, "How are they going to do that?"

The Concept of the New QV

The new QV is in the process of development. We do have a draft that has received wide distribution comment within ASME. Comments have been resolved for the most part and the next step is the ballot process within ASME. Also, a big plus would be a future endorsement from the U.S. Nuclear Regulatory Commission, something that QME does not yet have.

The new QV considers the following:

- The PC has given us significant analytical power.
- The scope of what needs to be qualified as an active component is quite small in comparison to the overall population in a typical Nuclear Power Plant.
- We now have significant experience with valve testing almost exclusively from industry experiences in responding to NRC Generic Letter 89-10.

- Safety and Relief valves have been flow qualified for years as part of ASME Sections III and VIII.
- New qualification technologies will become available significantly faster than they can be added into QV.
- QV was intended for new construction. However, there may be application for existing Nuclear Power Plants and, possibly, for other industries.
- The present QV can be quite cumbersome to read and understand. There are constant references back and forth to other sections.

Given these basic parameters, the new QV does the following;

- QV almost entirely abandons the parent/candidate concept and, instead, establishes qualification of an assembly and gives guidance on how to prove the production valve is essentially the same.
- The new QV is much less prescriptive in that it provides a set of parameters that must be met and then allows the valve designer/manufacturer to develop the method of qualification similar to what is presently done in the Pump Section of QME.
- The new QV purposely limits the scope of valves that need to be qualified. This is getting back to the original requirement of NRC Regulatory Guide 1.48, Standard Review Plan 3.9 and Generic Letter 89-10.
- The new QV establishes a link between QV and the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code), specifically, Code Case OMN-1 and Check Valve Performance Monitoring. This makes certain that the qualification parameters determined with a prototype can be demonstrated in the installation.
- The new QV recognizes that Safety and Relief valves have always had flow testing. QV allows the flow test to be used as credit rather than requiring a separate and different test.
- The new QV allows the valve manufacturer the flexibility to provide end loads to the piping designer that need to be kept to demonstrate isolation of a guillotine rupture. This is a direct result of new pipe stress analysis programs that make checking valve end loads relatively simple. Further, it excludes Safety and Relief valves from end load qualification because these valve types have always had flow induced end loads and piping designers design accordingly.
- The new QV makes the generation of a functional specification mandatory. This is to ensure that the valve designer and manufacturer know what is expected. Also, it provides information to the valve manufacturer wherein he/she can determine if there are system design functions that the type of valve cannot achieve.
- The new QV is reformatted so that the need to reference back and forth is greatly reduced although not completely eliminated. For the most part, once you've selected a valve type, you stay within that section.

A Glimpse at the new QV

Section QV provides for qualification of a valve assembly by a combination of testing and analysis. Functional qualification of a Valve Assembly by extension of Qualified Valve Assembly qualification through limited testing and demonstration of design similarity is permitted. This extension of qualification is based upon the condition that both the valve assemblies utilize the same design concept and that critical dimensional clearances are maintained. Diagnostic testing shall be performed during the qualification testing covered by this standard.

The excerpts from section QV are taken from Draft M of the standard, 2/23/04. This is the version that balloted by the Standards Committee. The published wording may be different.

A major difference between the present and future QV is the allowance of the use of Analysis. This is permitted within the following guidelines:

(a) Analysis is permissible provided that sufficient test verification exists to justify the analysis used, over the qualification conditions involved.

(b) Analysis methods may be used for ensuring accessories and associated attachments are rigid.

(c) Analysis methods based on extensive valve assembly testing programs may be used in conjunction with focused flow testing to demonstrate functional capability. The user should be cautioned that, because of difficulties associated with identifying and predicting factors which affect operating loads for certain types of valves (e.g., flexible wedge gate valves), even when those valve assemblies are identical, it may be necessary to limit the use of analysis in functional capability qualification. Analysis methods may be used in the accelerated environmental aging process per the provisions of Appendix QME QR-B.

The first parameter to consider for the qualification of a valve assembly is its intended use. As I mentioned before, QV qualification is limited to Active Valve Assemblies. The QV definition of Active Valve Assembly is:

"A valve assembly that is required to change position to perform its Nuclear Safety Function."

Note that most Nuclear Safety Related Check Valves fit the definition of "active;" however, the Committee is still formulating a definition.

The new QV is arranged so that qualification requirements are based on valve assembly type. Within each type, there are two categories. The categories are defined as follows:

"Qualification Category A, Valve assemblies that are required to open against or isolate flow under conditions associated with pipe rupture. This flow includes blowdown flow (e.g., injection into a vessel, or isolating a line break with a flow regime that exhibits two phase flow or flow velocities above those experienced in a pumped flow application). Valve assembles in this Category may be in pipes where the ASME Section III stress allowable for the attached pipe may exceed Level B."

"Qualification Category B, Valve assemblies that are required to open to permit flow or close to isolate flow but are not required to open against or isolate flow associated with a pipe rupture. Valve assemblies in this Category are in pipes where the ASME Section III stress allowable for the attached pipe does not exceed Level B. If piping system stress analysis indicates that the Level B stress allowable may be exceeded, then the valve assembly must be categorized as Category A."

Note that these definitions provide linkage to ASME B&PV Section III. This recognizes that pipe loads may be kept below those that cause deformation of the pipe.

With information on valve Type and Qualification Category, qualification requirements are obtained from the following table:

Valve Assembly Qualification Requirement Matrix

Note that each qualification parameter has its own section for each type of valve. This does create some repetition in QV but it does make it much easier for the user to follow the requirements. Referencing back and forth, as is required in the present QV, is significantly reduced. Also, note that qualification for Relief Valves is significantly reduced. This recognizes that relief valves by their nature cannot be Qualification Category A.

Some typical qualification requirements are as follows:

Environmental and Aging

This qualification parameter makes use of experience gained during initial tests for the GL 89-10 program. It also makes use of IEEE 382.

> The qualification of non metallic parts that are critical to function is contained in QR-B.
>
> Friction of valve internal sliding surfaces can increase with age until a plateau is reached. Further, inspections and disassembly/reassembly of valves that expose valve internal surfaces to air can result in a temporary reduction in friction coefficients. Qualification of functional capability must address these phenomena when establishing valve operating requirements.

Environmental Qualification of actuators is performed in accordance with IEEE 323 and IEEE 382 Qualification of other non-metallic parts that are critical to valve assembly performance may be performed in accordance with QR-B.

Sealing capability

This section is separated into main seat and stem leakage. This is the least modified section of QV.

Parameter	Power Actuated		Self Actuated		Relief	
	Cat A	Cat B	Cat A	Cat B	Cat A	Cat B
Seismic	QV-7450	QV-7450	Not Required	Not Required	Not Applicable	QV-7650
End Load	QV-7440	Not Required	QV-7540	Not Required	Not Applicable	Not Required
Functional	QV-7460	QV-7460	QV-7560	QV-7560	Not Applicable	QV-7660
Environmental	QV-7420	QV-7420	QV-7520	QV-7520	Not Applicable	QV-7620
Sealing Capability	QV-7430	QV-7430	QV-7530	QV-7530	Not Applicable	QV-7630

Note 1: Relief valves, by function of their purpose (i.e. pressure relief) cannot be Category A.

Note 2: End Load testing is not required by the definition by the definition of Category B.

Note 3: Seismic evaluation of Self Actuated valves is not required due to the lack of an extended structure.

End Loading

The consideration of end loading is significantly different than the present QV. The new requirements are:

> All valves to be qualified to this document shall be designed so that they are in compliance with the rules of ASME B&PV Code Section III subsections NB, NC, or ND 3521 (1) & (2).
>
> The end loading test is not required if, (1) the intended application for the valve does not impose significant end load reactions (e.g., a drain valve with piping attached to one end of the valve does not impose significant loading); or (2) the valve is designed to be installed in piping by bolting the valve between pipe flanges, and the valve body has a generally cylindrical cross section (except for through bolting holes and a provision for actuator mounting and entrance of the valve stem/shaft) of such proportions that the length of the valve body parallel to the pipe run is equal to or less than the inside diameter of the valve (e.g., a wafer style butterfly valve).
>
> For Category A valve assemblies, one of the following is required:
>
> 1) Qualify analytically, using a test verified method, the maximum load (forces and moments) that can be placed on the valve body such that operation is not adversely affected. In turn, this load is to be supplied to the pipe system designer who must design his system such that the load cannot be exceeded.
>
> 2) Qualify by test for the maximum load that can be placed on the valve body such that operation is not adversely affected. In turn, this load is to be supplied to the pipe system designer who must design his system such that the load cannot be exceeded.
>
> 3) Require that the pipe/support system be designed such that the maximum load transmitted to the valve does not exceed the Level B stress limits of ASME Section III.
>
> If options 1 or 2 are chosen the valve designer shall determine the maximum load that the valve can sustain without loss of function. This information shall be included in the ASME Section III design report for the valve.
>
> End load qualification is not required for Category B valve assemblies.

Seismic Capability

The new QV provides several options for Seismic Qualification. Section QR-A is also extensively rewritten. It is presently in the ballot process at ASME and I will not go into details in this presentation. However, QR-A does allow the use of experience data for Seismic Qualification. This is significantly different than the present QME. Seismic requirements for power operated valve assemblies are:

> (a)Seismic qualification is intended to demonstrate the ability of a valve assembly to withstand a loading which is representative of the specified seismic load qualification level.
>
> (b)Qualification of valve assemblies shall be in accordance with of IEEE Std-344 as addressed in NRC Regulatory Guide 1.100 (Revision 2) or Appendix QR-A.
>
> (c)All essential-to-function accessories shall be attached to the valve assembly. The essential-to-function accessories that have not been previously qualified in accordance with IEEE Std-344 as part of the actuator assembly shall be seismically qualified by test in accordance with the test section of IEEE Std-344 or Appendix QR-A.

Functional Qualification

Functional qualification, or flow capability, is another significantly different section in QV. Specifically for Power Actuated valves, this section makes extensive use of experience obtained during the GL 89-10 programs. It does allow the use of analytical data if such data is test verified. There is a large deal of this information available to users groups. This section allows the use of this data or allows a manufacturer to establish their own. However, the prescriptive requirements are now removed for the most part.

> The qualification of the functional capability of a Valve Assembly shall be justified using a combination of analysis and diagnostic test data. Test-based methodologies that have been demonstrated to reliably predict valve assembly performance may be used to supplement the testing in order to minimize the amount of testing needed to qualify the Valve Assembly. The following activities shall be performed to justify the qualification of the functional capability of the Valve Assembly:
>
> (a) Identify the manufacturer, type, size, materials (including internal parts) and rating; stem packing; and corrosion inhibitor (as applicable) for the valve to be qualified.

(b) Perform an internal inspection of the valve for material, surface condition, and critical internal dimensions (including valve internal clearances and edge radii). Evaluate worst-case tolerance combinations in the manufacturing process and verify that the valve will behave predictability.

(c) Establish any orientation requirements and any system piping constraints that are applicable to the qualification of the valve.

(d) Establish fluid conditions (including blowdown) and stroke time requirements that the valve is being qualified to.

(e) Determine the seat leakage limitations (including directional sealing) of the valve.

(f) Determine the stem leakage limitations of the valve.

(g) While collecting diagnostic test data (including valve stem thrust and/or torque; fluid pressure and temperature; and stroke time), cycle the valve under static fluid conditions throughout the valve stroke in both the opening (including unseating) and closing (including seating) directions and verify proper valve assembly.

(h) While collecting diagnostic test data (including valve stem thrust and/or torque; fluid pressure and temperature; and stroke time), cycle the valve in both the opening and closing directions until the coefficient of friction has stabilized and baseline performance parameters established.

(i) While collecting diagnostic test data (including stem thrust and/or torque; fluid pressure and temperature, and stroke time), cycle the valve under applicable fluid temperature, pressure, and flow conditions (from ambient to hot water and steam conditions), environmental conditions, and stroke time requirements throughout the valve stroke (including seating and unseating) and verify the functional capability of the valve under design-basis conditions.

(j) Determine whether the valve is susceptible to pressure locking and/or thermal binding. If so, establish design limitations to prevent pressure locking and/or thermal binding.

The new QV allows the qualification of the actuator and valve separately.

Extrapolation of Qualification for Functional Capability

The new QV abandons the Parent/Candidate concept of the present QV. It does permit extrapolation of qualification of function.

The extrapolation of the qualification of the functional capability of a Qualified Valve Assembly to another Valve Assembly shall be justified using a combination of analytical comparison of physical attributes and diagnostic test data. Test-based methodologies that have been demonstrated to reliably predict valve assembly performance may be used in lieu of the testing needed to extrapolate the qualification to another Valve Assembly.

Functional Capability of Production Valves

Verification of production valves relies heavily on new technology. This can be thought of as a baseline for in service tests during the life of the valve.

The functional capability of production valve assemblies shall be demonstrated based on verification of the physical attributes, application, and diagnostic test data of the production valve assembly to its Qualified Valve Assembly. At the discretion of the valve assembly owner, the production valve assembly testing may be performed following final installation of the valve assembly. The following activities shall be performed to demonstrate the functional capability of production valve assemblies:

(a) Verify applicability of the production valve type, size, material (including internal parts) and rating; orientation; piping system constraints; stem packing; and any corrosion inhibitor to the Qualified Valve.

(b) Perform an internal inspection of the production valve for material, surface condition, and critical internal dimensions (including verifying that valve internal dimensions, clearances, and edge radii are within manufacturing tolerances) to establish applicability to the Qualified Valve.

(c) Verify applicability of fluid conditions and stroke-time requirements for the production valve to the Qualified Valve.

(d) Verify that the seat leakage limitations (including directional sealing) of the Qualified Valve are applicable to the production valve.

(e) Verify that the stem leakage limitations of the Qualified Valve are applicable to the production valve.

(f) While collecting diagnostic test data (including valve stem thrust and/or torque; fluid pressure and temperature; and stroke time), cycle the production valve under static fluid conditions throughout the valve stroke in both the opening (including unseating) and closing (including seating) directions in order to verify proper assembly.

(g) Verify applicability of the functional capability (including stroke time) of the production valve for opening and closing under fluid conditions to the Qualified Valve through the use of specific test data or a test-based qualification methodology.

(h) Verify that the production valve addresses any pressure locking and/or thermal binding limitations of the Qualified Valve.

Note here that linkage has been made to the OM Code.

Post installation Verification and IST Baseline

The new QV makes a clear link to OM in this regard. Note how on the front end the valve is linked to ASME Section III and on the back end to IST.

The owner is responsible, after the production valve assembly has been installed in the plant, to cycle the production valve assembly under representative fluid conditions as necessary to collect diagnostic data (including valve stem thrust and torque; fluid pressure and temperature; stroke time; MOV motor torque, voltage and current; and AOV operating air pressures and current signals, as applicable) throughout the valve stroke to verify the production valve assembly meets the functional requirements of the qualified valve assembly. The owner can use this diagnostic data to establish the baseline requirements required by In-Service Testing, Section C of ASME OM Code

Valves Other Than Power Operated Valves

The intent of this presentation is to give an overview of the new QV. The foregoing is generally for power operated valve assemblies. There are separate sections for Check Valves and Relief Valves. I will not repeat similar qualifications for the other valve types but I will provide a few new concepts.

Seismic qualification of Check Valves

Seismic qualification of check valves is not required under this standard and may be covered by applicable design codes.

Those check valves with actuating means involving external weights, springs, or a power actuator whose purpose is to provide positive closure or to assist in closure may be qualified by analysis which verifies that the actuating device can not degrade the function or operability during and after a seismic event. Additionally, those check valves with an external actuating device whose sole purpose is to provide a means for in-service testing of operability may be qualified by analysis which verifies that the actuating device can not degrade the function or operability during and after a seismic event.

Functional Qualification For Check Valves

This parameter is significantly changed from the present QV. The difference is that full flow need not be developed. Rather, the disc position is now considered. This limits the flow significantly making qualification somewhat easier.

(a) The valve functional qualification establishes key performance parameters necessary for the evaluation of proper valve sizing to maintain the valve disk in the full open position under normal flow conditions, and the evaluation of valve adequacy for service applications involving flow reversal and resulting pressure surge produced by valve closure. The following activities shall be performed to justify the qualification for functional capability of the Valve assembly.

Identify manufacturer, type, size, material (including internal parts) rating; stem packing; and corrosion inhibitor (as applicable).

Establish orientation and system piping application.

Establish applicable fluid and system flow conditions.

Establish sealing capability requirements for valve.

Establish stem shaft leakage limitations for valve.

(b) Test-based methodologies that have been demonstrated to reliably predict valve assembly performance may be used to supplement valve-specific testing to minimize the range of flow testing in qualifying the Valve Assembly.

Post installation Verification and IST Baseline for Check Valves

Once again, clear linkage to ASME OM is established.

After the valve has been installed in the plant the valve shall be cycled under representative fluid flow conditions as necessary to collect of diagnostic data (disk position etc. as applicable) for use in future performance monitoring as required by Section ISTC of ASME OM Code.

Relief Valves

The new QV recognizes that functional qualification of Relief valves is already adequately covered by other codes and standards and that there is a significant experience database for relief valves.

Functional Qualification for Relief Valves

Functional qualification for Pressure Relief assemblies shall be as delineated in ASME B&PV Code Section III, Subsections NB, NC or ND 7700. The rules of Section III also govern the extrapolation of test results as well as the extension of test results to production valves.

Tests Prior to Initial Operation for Relief Valves

Valve assemblies shall be tested prior to initial installation as delineated in ASME OM Code, Appendix I, subsection I-3100 or I-7100.

Post installation Verification and IST Baseline

After the valve assembly has been installed in the plant the valve shall be tested as required by ASME OM Code, Appendix I, subsection I-3200 or I-7200.

Conclusions

The new QV is intended to recognize new technology as well as experience gained in the last thirty years since the issuance of NRC Regulatory Guide 1.48. It has become easier to read and understand and, hopefully, clears up confusion in the present QV. This is all intended to increase the safety of the public while addressing the large expense of Active Valve Qualification.

References

- Nuclear Regulatory Commission Regulatory Guide 1.48 (May 1973), "Design Limits and Loading Combinations for Seismic Category 1 Fluid System Components," withdrawn 50FR9732, 3/11/1985.
- Nuclear Regulatory Commission Regulatory Guide 1.100 (Revision 2, 1988), “Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants.”
- Nuclear Regulatory Commission NUREG-0800, "Standard Review Plan," Section 3.9.3, "ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures."
- Nuclear Regulatory Commission Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance."
- ANSI N278.1-1975, “Self-Operated and Power-Operated Safety-Related Valves Functional Specification Standard.”
- ANSI/ASME B16.41-1983, "Functional Qualification Requirements for Power-Operated Active Valve Assemblies for Nuclear Power Plants."
- ASME *Boiler & Pressure Vessel Code*, Section III, “Rules For Construction of Nuclear Facility Components.”
- ASME *Boiler & Pressure Vessel Code*, Section VIII, “Rules For Construction of Pressure Vessels.”
- ASME QME-1-2002, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants.”
- ASME *Code for the Operation and Maintenance of Nuclear Power Plants*, OM-2001.
- ASME Code Case OMN-1-1999, “Alternative Rules for Preservice and Inservice Testing of Certain Electric MOV Assemblies in LWR Power Plants.”
- IEEE Std-344-1987, “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”
- IEEE Std-382-1996, “IEEE Standard for Qualification of Actuators for Power-Operated Valve Assemblies with Safety-Related Functions for Nuclear Power Plants.”
- MSS, Manufacturers Standardization Society of the Valve Industry.

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IMPLEMENTATION OF EXPERIENCE-BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

HISTORICAL PERSPECTIVE

Timothy M. Adams
Stevenson and Associates

ABSTRACT

In the early 1980s the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to disposition Unresolved Safety Issue USI A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experience-based equipment qualification could explicitly be incorporated into ASME QME-1 and IEEE-344. The joint ASME-IEEE working group concluded that experience-based rules could be introduced into IEEE-344 and ASME QME-1. The joint task group proposed a set of technical guidelines for implementation of experience-based qualification in ASME QME-1 and also provided a strategy for implementation. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ) to implement the recommendations of the joint ASME-IEEE Special Working Group. The Subgroup recently completed this effort and the QME-1 standard will include a prescriptive methodology to apply actual earthquake experience to the seismic qualification of mechanical equipment. This paper provides background and history on this development effort. It also touches on the general principals of experience-based seismic qualification as it applies to Mechanical Equipment.

BACKGROUND

Throughout the 1980s, it became evident that important insights in the seismic performance of equipment, both mechanical and electrical, could be gained by a systematic study of data collected following large earthquakes and seismic testing. This led to several initiatives in the commercial nuclear industry to apply experience data for the seismic qualification of mechanical and electrical equipment.

INITIAL APPLICATIONS OF EXPERIENCED BASED DATA

This section overviews several of initial applications of experienced based seismic qualification that were implemented by the commercial nuclear power industry and the US Department of Energy.

SQUG Effort

In December 1980, the Nuclear Regulatory Commission (NRC) Staff initiated an unresolved safety issue, USI A-46, "Seismic Qualification of the Equipment in Operating Plants," related to seismic adequacy of mechanical and electrical equipment in older nuclear plants. This issue impacted approximately one half of the operating commercial nuclear power plants in the United States. In response to this generic letter, the commercial nuclear utility industry formed the Seismic Qualification Utility Group (SQUG) as the focal point for the resolution of USI A-46. After substantial technical research by both the SQUG and the NRC regarding this issue, the NRC published, in 1987, a detailed approach for resolving USI A-46, in Generic Letter 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46." The Generic Letter Procedure sets forth an approach for verifying seismic adequacy of equipment using earthquake experience data supplemented by test results and analyses, as necessary. Licensees subject to USI A-46 were encouraged to participate through SQUG, in a generic program to accomplish seismic verification of equipment. As a result, SQUG developed the "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment."[6] The GIP uses earthquake experience data extensively to demonstrate the seismic adequacy of equipment.

The use of the SQUG-GIP was the first large-scale application of earthquake experience data to demonstrate the seismic adequacy of electrical and mechanical equipment. It was applied to over one half of the commercial nuclear power facilities in the United States. The period of application of the SQUG-GIP for resolution of USI A-46 was from the late 1980s until the mid-1990s.

STERI Effort

Seismic qualification for equipment originally installed in nuclear power plants was typically performed by the original equipment suppliers or manufacturers (OES/OEM). Qualification was usually based on analysis and/or testing performed on prototypes. Sub-components of such equipment were qualified by virtue of their performance in the host equipment. Quality assurance program controls were implemented by the suppliers and normally invoked by utilities to assure continued qualification of replacement items for use in the originally installed equipment. Many of the original equipment suppliers and manufacturers no longer maintain quality assurance programs that provide adequate controls for supplying nuclear equipment. Further, many of these venders are no longer in business. Consequently, utilities themselves must provide reasonable assurance for the continued seismic adequacy of replacement items.

To address the issue, the Electric Power Research Institute (EPRI) working in conjunction with SQUG developed the guideline for Seismic Technical Evaluation of Replacement Items (STERI).[7] This guideline acknowledged the use of experienced based seismic qualification to demonstrate the seismic adequacy of replacement equipment for electrical and mechanical equipment.

NARE

A second program that evolved from the SQUG-GIP effort for the resolution of USI A-46 was the New and Replacement Equipment (NARE) Program [8,10]. Jointly developed by SQUG and EPRI, this guideline provided prescriptive direction on the use of earthquake experience data to demonstrate the seismic adequacy of mechanical and electrical equipment. The application of the NARE guidelines is limited to those commercial nuclear plants that used the SQUG-GIP for the resolution of USI A-46 and adopted the use of the SQUG-GIP into their licensing basis.

DOE-GIP

At U.S. Department of Energy (DOE) facilities, safety analyses and facility-specific modifications in many cases required the evaluation of systems and components subjected to seismic hazards. In the mid-1980s, DOE developed a program that provides guidance for evaluating DOE equipment and distribution systems using experience data from past seismic events and shake table tests.[9]

A primary objective of the DOE Seismic Evaluation Procedure is to provide comprehensive guidance for consistent seismic evaluations of equipment and distribution systems in DOE facilities. Due to the evolution of design and operating requirements, developments in engineering technology, and differing hazards and missions, DOE facilities embody a broad spectrum of design features for earthquake resistance. The earliest-vintage facilities often have the least seismic design considerations and potentially exhibit the greatest difference between their design basis and what DOE requires today for seismic design criteria for new facilities. The approach sometimes used to review the seismic capacity of equipment and distribution systems included sophisticated evaluations or qualification testing that can be very time consuming, complex, and costly. This procedure is designed to be a cost-effective method of enhancing the seismic safety of facilities by emphasizing the use of facility walkdowns and engineering judgment based on seismic experience data.

The DOE Seismic Evaluation Procedure was adapted from Part II of Revision 2 of the SQUG-GIP used by the commercial nuclear power industry. The DOE Seismic Evaluation Procedure built on the procedures and screening criteria in the SQUG-GIP by incorporating DOE-specific requirements and guidance, and broadening the application of the experience-based methodology to equipment classes not contained in the SQUG-GIP.

TRADITIONAL QUALIFICATION APPROACH

Component (excluding distribution systems) seismic qualification as it relates to commercial nuclear power plants can be broken down into two primary areas: electrical and mechanical components. The qualification criteria for mechanical components can also be broken down into two categories:

(a) Leak tight structural integrity

(b) Operational design requirements.

Leak tight structural integrity for most pressure retaining mechanical components since the early 1970's has required some level of analytical evaluation either by meeting explicit ASME *Boiler and Pressure Vessel Code* (BPVC)[1] equations or meeting layout and support requirements which can be demonstrated to meet ASME BPVC design equation requirements. The design of low or zero pressure retaining mechanical components (such as fans, air handling units, chillers, atmosphere storage tanks, etc.) is covered by other industry standards such as ASHRAE, SMANCA, API, etc.

The operability seismic qualification of mechanical components used in nuclear power plants since 1994 was covered by the ASME Committee on Qualification of Mechanical Equipment (QME) who have developed operability qualification standards for pumps and valves. A non-mandatory Appendix A of Section QR of the QME-1 Standard,[2] which was published by ASME in June 1994, provides some general guidance on the application of experienced based seismic qualifications. Prior to the issuance of QME-1, most commercial nuclear power plants used IEEE-344[3] for the seismic operability qualification of mechanical equipment. In fact, all commercial nuclear power plants are currently licensed to IEEE-344 and/or SQUG-GIP for the seismic qualification of mechanical equipment.

Electrical components unlike mechanical components have historically not been required (for seismic qualification) to meet any explicit pressure retaining requirements. They have been qualified by demonstrating operability of performance requirements only in accordance with IEEE (primarily IEEE-344) requirements. IEEE-344-87 Section 9 provides general requirements for the use of experienced based seismic qualification.

ASME/IEEE EFFORTS TO INCORPORATE SEISMIC EXPERIENCED BASED QUALIFICATION INTO INDUSTRY CONSENSUS STANDARDS

With the experience gained in implementing these earthquake-based rules as a backdrop, the ASME and IEEE formed a joint working group in the early 1990s to investigate whether earthquake-based experience could explicitly be incorporated into ASME QME-1 and IEEE-344 Standards. Note that the existing revisions of both QME-1 and IEEE-344 Standards contained suggested approaches for use of experience data, but they are based on explicit one-to-one similarity sand do not incorporate the lessons learned through the 1990s. The joint ASME-IEEE Special Working Group concluded that experience based rules could be introduced into IEEE-344 and ASME QME-1 Standards, and published a “Recommendation for the Inclusion of Experience Base Seismic Qualification Methods into IEEE-344 and ASME-QME-1.”[5] A strategy for implementing this approach was also prepared.[4]

ASME QME Efforts

In response, ASME QME committee formed a Subgroup on Dynamic Qualification (SGDQ) to implement the recommendations of the joint ASME-IEEE Special Working Group. The first draft revisions of Section QR and Appendix QR-A, which incorporated the experience-based approach, were issued for general review in December 1999. These resulted in more than 110 comments on the proposed changes to Section QR and Appendix QR-A. The Subgroup addressed all comments received. The resolution to the comments resulted in a significant rewrite by the SGDQ of the proposed QR and Appendix QR-A language. As a result, updates of Section QR and Appendix QR-A were issued for a second general review on December 2, 2000. This review resulted in 200 additional comments on the proposed code language. The Subgroup reviewed and addressed all of the 200 comments. All persons making comments were formally advised as to how the Subgroup addressed their comments in a letter issued in the third Quarter of 2002.

At the time of the writing of this paper, the final proposed changes to Section QR and Appendix QR-A have been formally Letter Balloted by the ASME Qualification of Mechanical Equipment Main Committee and the ASME Board of Nuclear Codes and Standards (BNCS). Negatives received by the QME main Committee have been resolved and the action has passed the committee. The BNCS procedural negatives are in the process of being resolved. It is hoped the updated sections of QR and QR-A can be issued formally in the 4th Quarter of 2004.

IEEE Effort

IEEE under the Nuclear Power Engineering Committee (NPEC) has initiated an effort to incorporate the recommendations of IEEE/ASME Special Working Group into the IEEE-344 standard. The work is under the cognizance of the IEEE-344 working group. The working group has completed its initial work and the proposed revisions to IEEE-344 are now in the process of being balloted by NPEC.

Conclusion

The proposed changes to Section QR and Appendix QR-A are the culmination of over five years of effort by the SGDQ, and over 20+ years of industry application. During that time, the SGDQ has worked closely with the QME Main Committee, the Seismic Qualification Utility Group (SQUG), the U.S. NRC, the U.S. domestic utilities, the IEEE-344 Working Group and various mechanical equipment vendors, in an attempt to address all concerns and comments in relation to the application of experience-based methods to the seismic qualification of mechanical equipment. It is hoped that by the time this paper is presented the revised Section QR and Appendix QR-A of QME-1 will have been accepted and on their way to publication.

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[4] Adams, Timothy M., "A Strategy for Implementation of Experienced Based Seismic Equipment Qualification in IEEE an ASME Industry Standards." Presented at the 1996 PVP conference in Montreal, Canada, PVP Vol. 340, pp. 321-329.

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IMPLEMENTATION OF EXPERIENCE-BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

THE OVERALL TECHNICAL BASIS

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ABSTRACT

In the early 1980s, the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to resolve Unresolved Safety Issue (USI) A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A-46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experience-based equipment qualification could be explicitly incorporated into ASME Standard QME-1 and IEEE Standard 344. The joint ASME-IEEE working group concluded that experience-based rules could be introduced into IEEE 344 and ASME QME-1. The joint working group proposed a set of technical guidelines and a strategy for use in implementing experience-based qualification in ASME QME-1 and IEEE 344. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ). In 1995, this Subgroup began to develop modifications to the ASME QME-1 Standard that incorporate a detailed methodology for the implementation of earthquake experience-based seismic qualification for mechanical equipment. The updated sections of the QME-1 Standard were approved by the QME Main Committee in the third quarter of 2003. The standard is expected to be approved by the ASME Board of Nuclear Codes and Standards before the end of 2005. This paper provides the overall technical basis for the earthquake experience-based method included in the updated section of the QME-1 Standard. This includes a presentation of the key features of the methodology, the basis for the approach selected, and the basis for the requirements in the standard.

INTRODUCTION

Use of earthquake experience is a well-established, effective method for verifying the seismic adequacy of equipment and is another tool for seismic qualification of equipment in nuclear power plants. Prior to its development, the nuclear power industry relied solely upon testing and analysis as the basis for seismic qualification of mechanical and electrical equipment. However, use of these traditional methods was not well suited to verifying the seismic adequacy of equipment that is already installed in older operating reactors, i.e., nuclear power plants that began construction prior to about 1975. Accordingly, the U.S. Nuclear Regulatory Commission (NRC) embraced use of experience-based methods for resolution of Unresolved Safety Issue (USI) A-46 in Generic Letter (GL) 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46." [1] In this generic letter, on page 1, the NRC Staff recognized the benefits of using experience-based methods instead of traditional seismic qualification methods for as-installed equipment:

> "Direct application of current seismic criteria to older plants could require extensive, and probably impracticable, modification of these facilities.[1] An alternative resolution of this problem is set out in the enclosure to this letter. This approach makes use of earthquake experience data supplemented by test results to verify the seismic capability of equipment below specified earthquake motion bounds. In the staff's judgment, this approach is the most reasonable and cost-effective means of ensuring that the purpose of General Design Criterion 2 (10 CFR Part 50 Appendix A) is met for these plants.1"

Most of the utilities that operated the 70 nuclear units affected by USI A-46 formed an owners' group in the early 1980s to develop use of experience data to resolve this safety issue. This owners' group, the Seismic Qualification Utility Group (SQUG), worked with the NRC to develop the methodology and procedures to apply experience data. In addition, SQUG and the NRC worked with the Senior Seismic Review and Advisory Panel (SSRAP), a group of recognized seismic experts from industry, academia, and national laboratories to develop this method. To date, all of the plants still operating that were affected by USI A-46 have applied the experience-based methods developed by SQUG and successfully resolved this safety issue.

Since this experience-based method gained acceptance and was being widely applied in the nuclear power industry, the ASME and IEEE formed a joint working group in the early 1990s to investigate whether this method could be explicitly incorporated into ASME QME-1 and IEEE 344 for seismic qualification of mechanical and electrical equipment. Both organizations have subsequently developed draft revisions of their standards with new sections added to cover use of experience data. The QME Main Committee approved the updated sections of the QME-1 Standard in the third quarter of 2003. The ASME Board of Nuclear Codes and Standards is expected to approve this revision before the end of 2005. The Nuclear Power Engineering Committee of IEEE approved a draft revision of IEEE 344 in July 2003 for general balloting by the IEEE Standards Association. The balloting is taking place during the first and second quarters of 2004.

The experience-based method uses a different approach to seismic qualification of equipment than is used in traditional testing and analysis methods. This paper summarizes the key features of the experience-based method, as applied in the QME-1 Standard, and describes the overall basis for the approach and requirements in the standard.

KEY FEATURES OF EXPERIENCE-BASED METHOD

The five key features of the earthquake experience-based method, as used in the QME-1 Standard for seismic qualification of equipment, are listed below:

(1) A Reference Equipment Class is defined based on equipment performance data collected from facilities where strong ground motion earthquakes had occurred.

(2) Ground motion response spectra are determined at the facilities where the equipment performance data was collected.

(3) An Earthquake Experience Spectrum (EES) is developed to represent the seismic capacity of the equipment from which performance data was collected.

(4) Candidate Equipment is compared to the attributes of the equipment in the Reference Equipment Class.

(5) Seismic demand on the Candidate Equipment is compared to the EES.

A summary of each of these key features follows.

Reference Equipment Class Definition. Data are collected on the performance of equipment that has been exposed to strong ground motion earthquakes. A minimum of 30 independent items of equipment is obtained for each class of equipment being developed. Having 30 independent items provides a statistically significant source of data. The type of data to be collected includes the physical and operational characteristics that define the range of equipment physical characteristics, dynamic characteristics, and functions. These data are used to define the bounds of equipment covered by the Reference Equipment Class. These data are then used to define a set of Inclusion Rules that characterize the features of the equipment that are important to seismic adequacy. In addition, the experience data are used to define a set of Prohibited Features. The Prohibited Features include design details, materials, construction features, and installation characteristics that have resulted in seismic-induced failure of equipment to maintain its structural integrity and perform its specified function.

Ground Motion Response Spectra Determination. A free field horizontal ground response spectrum is established at each of the facilities where the equipment performance data were collected. These facilities are called Reference Sites. This response spectrum is based on recorded data within two structural diameters of the facility, if possible. However, if such data are not available, then other nearby free field ground motion recordings may be used to develop an estimate. This estimate is based on multiple attenuation relationships from strong-motion earthquakes that have similar tectonic environments, crustal properties, and seismological parameters. These ground motion response spectra are considered an estimate of the seismic excitation experienced by the equipment at these Reference Sites. Equipment performance data and the ground response spectra are obtained from at least four different Reference Sites and from at least four different earthquakes. Such diversity provides a measure of assurance that the equipment in the Reference Equipment Class had been exposed to seismic loadings that are broadband and statistically independent.

Earthquake Experience Spectrum Development. The ground response spectra from the Reference Sites are combined to form a weighted average, called the Earthquake Experience Spectrum (EES). The EES represents the seismic capacity of the equipment in the Reference Equipment Class. The weighting factor is based on the number of independent items at each Reference Site.

Candidate Equipment Comparison to Reference Equipment Class. The attributes of the Candidate Equipment being qualified are then compared to the Inclusion Rules and

Prohibited Features of the Reference Equipment Class. If there is a match, the Candidate Equipment is considered to be covered by the Reference Equipment Class. Candidate equipment of a newer vintage than the equipment used to establish the Reference Equipment Class should be evaluated for any significant changes in design, material, or fabrication that could reduce its seismic capacity compared to the Reference Equipment Class.

Seismic Demand Comparison to EES. The seismic demand on the Candidate Equipment, i.e., the Required Response Spectrum (RRS), should be enveloped by the EES for the Reference Equipment Class. The RRS used in this comparison should be a median-centered in-structure response spectrum so that unnecessary additional conservatisms are not introduced into this evaluation; the EES already includes several conservatisms since it is based on free-field ground motion at the Reference Sites rather than the amplified in-structure seismic motions experienced by the Reference Equipment.

Using these five key features of the earthquake experience-based method provides an effective alternative to seismic qualification of equipment using testing and analysis methods.

OVERALL BASIS FOR EXPERIENCE-BASED METHOD

The experience-based method is predicated on the premise that industrial-grade equipment is typically rugged and can withstand the seismic excitation caused by large earthquakes. This premise was demonstrated during development of this method to support resolution of USI A-46. During the past 20 years that data were collected by SQUG, the vast majority of the mechanical and electrical equipment performed satisfactorily during and after significant earthquakes at numerous commercial facilities around the world. This record of success is particularly impressive in light of the fact that the equipment in these commercial facilities was purchased, installed, operated, and maintained without the benefit of extensive quality assurance programs like those used in the nuclear power industry. In those few cases where seismic failures of equipment were identified at these commercial facilities, SQUG performed root cause analyses to identify the specific vulnerabilities to avoid similar failures in nuclear power plants.

In addition to the large quantity of success data, the type of seismic failures that occurred supports the premise that industrial-grade equipment is rugged and can withstand large earthquakes. Most of the seismic failures were the result of a lack of adequate anchorage and adverse seismic interactions with nearby equipment and structures. There were very few failures attributed to equipment design features. It is important to note that these results are based on the performance of real equipment in real earthquakes. Therefore, it can be concluded that installation issues are of primary concern while equipment design features are not nearly as important.

One of the other strengths of the experience-based method is that it relies on a large quantity of equipment performance data collected from numerous earthquakes. This can be illustrated by a pile of sand, as shown in Figure 1, in which each grain of light-colored sand in the pile represents the equipment that successfully withstood the effects of earthquake. By contrast, the few instances of damage are represented by the large dark pieces in this sand pile. Because there are so much success data compared to failure data, the experience-based method departs from the traditional testing and analysis method where significant attention is paid to one-to-one similarity in the qualification process. By contrast, the experience-based method gives less emphasis to one-to-one similarity and instead defines seismic capacity for whole classes of equipment.

To illustrate the ratio of success to failure data, results of data collected for one of the equipment classes in the USI A-46 program are illustrated in Figure 2. The height of each bar in this chart represents the number of Motor Control Centers (MCCs) at facilities that experienced significant earthquakes. These bars, placed along the horizontal axis of this chart, are at the approximate Peak Ground Acceleration (PGA) experienced by the facility during the earthquake. Note that there were only three MCCs that failed to perform satisfactorily. These three instances (represented on the chart with Xs marked through the box) occurred at the Fertimex Fertilizer Plant. These failures occurred because the MCC anchorage was inadequate and the units fell over during the earthquake. By contrast, there were more than 160 instances where MCCs successfully withstood the effects of earthquakes, some of which were very large. Since not all of these MCCs experienced the highest levels of excitation, only those that experienced significant excitation were selected to define an equipment class and establish the Reference Spectrum for the USI A-46 program. Nevertheless, note that the three failures in Figure 2 occurred at a PGA of only about 0.33g, whereas there were about 80 MCCs that successfully withstood higher levels of excitation (up to a PGA of about 0.6g). This illustrates that MCCs (from various manufacturers) are seismically rugged and can withstand large earthquakes, provided they are adequately anchored to the floor.

Another reason that the earthquake experience-based method provides a reasonable alternative to traditional testing and analysis methods is that the seismic capacities that can be developed using this method are limited to the relatively low levels of ground motion from earthquakes. To illustrate this point, consider the capacity spectrum developed for the 20 classes of equipment covered by the USI A-46 program, as shown in Figure 3. This plot includes response spectra at the following four earthquake experience sites.

(1) Pleasant Valley Pumping Plant subjected to the 1983 Coalinga earthquake with a Magnitude of 6.7 and an Intensity of VII at the site.

(2) El Centro Steam Plant subjected to the 1979 Imperial Valley earthquake with a Magnitude of 6.6 and an Intensity of VIII at the site.

(3) Sylmar Converter Station subjected to the 1971 San Fernando earthquake with a Magnitude of 6.6 and an Intensity of VIII at the site.

(4) Llolleo Facility subjected to the 1985 Chile earthquake with a Magnitude of 7.8 and an Intensity of VIII at the site.

The average of these four horizontal ground response spectra is represented by the solid bold line in Figure 3, labeled as the Reference Spectrum for the USI A-46 program. Although the Reference Spectrum is applicable only for the USI A-46 program (i.e., the QME-1 Standard requires a separate, well-documented basis for establishing the seismic capacity of an equipment class), it illustrates the relatively low levels of earthquake ground response spectra for significant earthquakes.

One way to see how relatively low the ground response spectra are for real earthquakes is to compare these spectra to those typically used for shake table testing. Figure 4 includes a plot showing the maximum Test Response Spectrum (TRS) that is often used for shake table testing of components (dashed line). It has a peak spectral acceleration of 14g. In contrast, the USI A-46 Reference Spectrum, shown as the solid line near the bottom of this plot, has a peak spectral acceleration of only 1.2g. Although not all equipment is tested to the maximum TRS shown on this plot, many items of equipment used in nuclear plants are tested at levels many times higher than the ground response spectra for the plant. The point of this comparison is to illustrate that earthquake experience-based seismic capacities (e.g., the USI A-46 Reference Spectrum) are relatively low compared to the TRS used in seismic qualification testing. As such, the earthquake experience-based method can be considered a low level screening method for seismic qualification of equipment.

CONCLUSION

In conclusion, this paper describes the five key features and overall technical basis of the earthquake experience-based method included in the updated section of the QME-1 Standard. In particular, the earthquake experience-based method uses a different approach to seismic qualification of equipment than traditional testing and analysis methods. The earthquake experience-based method relies upon a large amount of success data, collected from several facilities that experienced large earthquakes. This data is used to develop a screening EES, based on the ground response spectra at these facilities, to represent the seismic capacity of the Reference Equipment Class.

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[2] ANSI/IEEE Std 344-1975, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

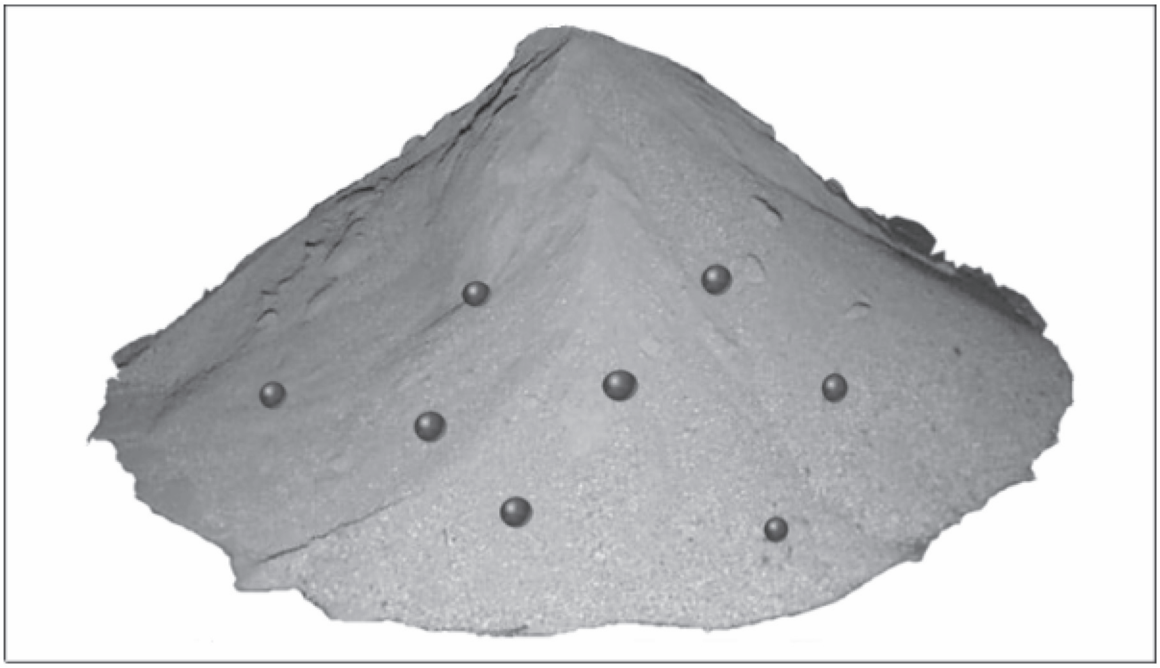

Figure 1 - Pile of Sand Illustrating Large Quantity of Experience Data

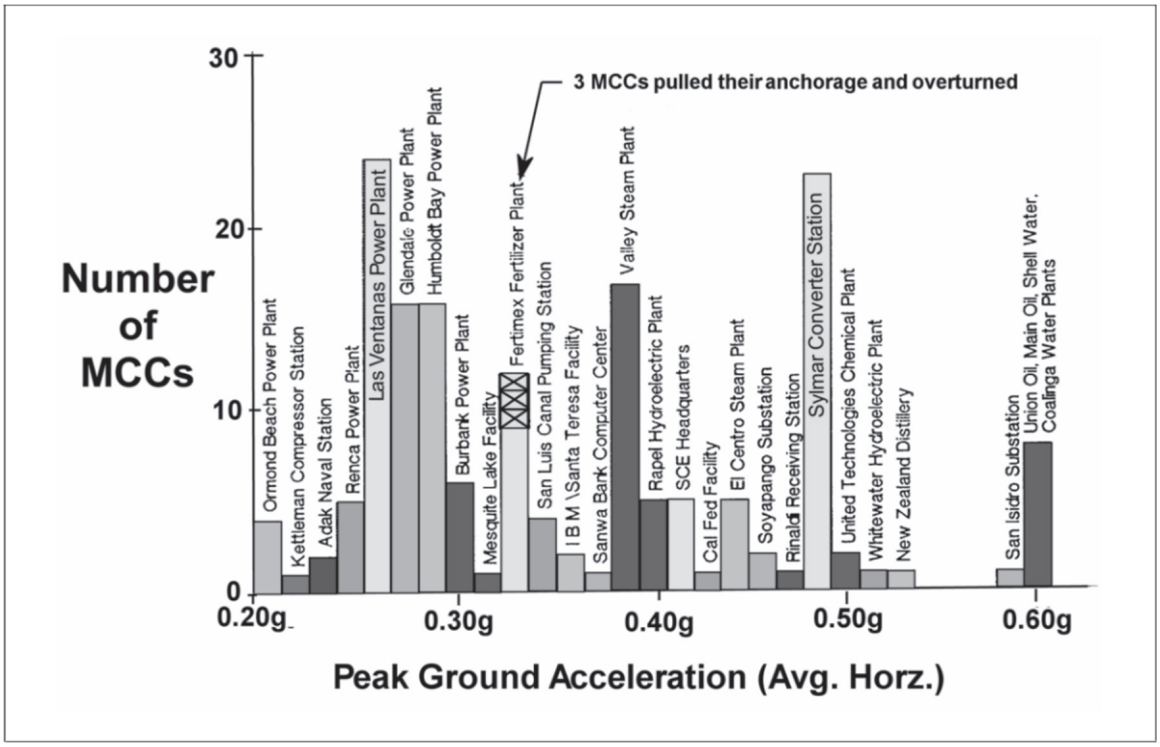

Figure 2 - Earthquake Experience Data for Motor Control Centers

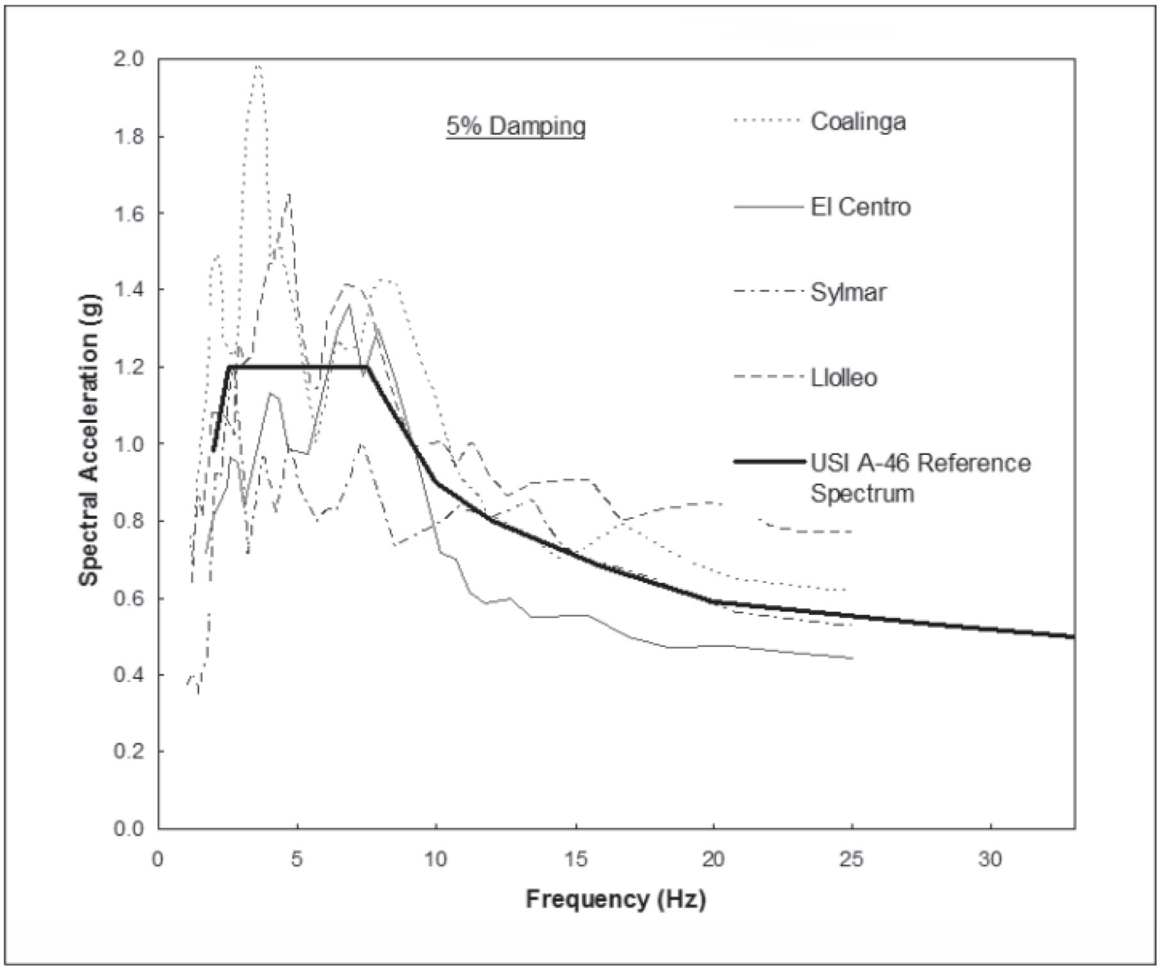

Figure 3 - USI A-46 Reference Spectrum and Earthquake Experience Ground Response Spectra

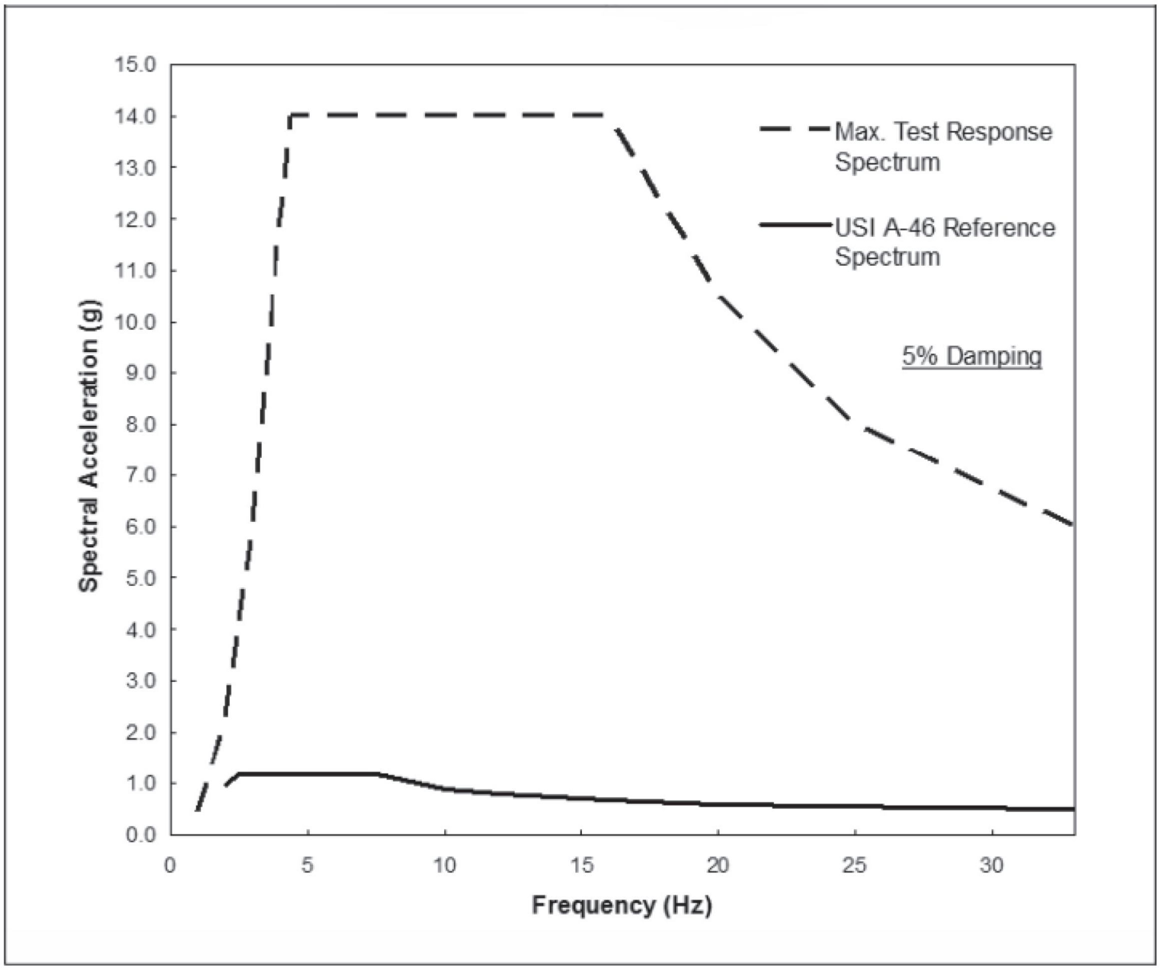

Figure 4 - Maximum Test Response Spectrum vs. USI A-46 Reference Spectrum

(Footnotes)

[1] The "facilities" and "plants" referred to in GL 87-02 are those nuclear power plants that had not committed to using IEEE Std. 344-1975 [2] for seismic qualification of equipment.

IMPLEMENTATION OF EXPERIENCE-BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

PROCEDURE FOR DATABASE GROUND MOTION DERIVATION

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ABSTRACT

In the early 1980s, the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to disposition Unresolved Safety Issue (USI) A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A-46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experienced based equipment qualification could explicitly be incorporated into ASME QME-1 and IEEE-344. The joint ASME-IEEE working group concluded that experience based rules could be introduced into IEEE-344 and ASME QME-1. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ) to implement the recommendations of the joint ASME-IEEE Special Working Group. The Subgroup recently completed this effort and the QME-1 standard will include a prescriptive methodology to apply actual earthquake experience to the seismic qualification of mechanical equipment. As part of theses changes, the QME-1 Standard provides requirements for using free field response spectra from earthquake data sites in developing an Earthquake Experience Spectrum (EES) for a class of equipment. This paper provides procedures, along with examples, for deriving earthquake data site free field response spectra meeting the requirements of the standard, using both on-site and remote earthquake records. The procedures presented are the basis of the requirements incorporated into the QME-1 Standard.

PROCEDURE FOR DERIVATION OF DATABASE SITE FREE FIELD RESPONSE SPECTRA

The procedure used to estimate a free field response spectrum at an individual earthquake database site will depend on the number and location of strong-motion recordings that are available from the earthquake that affected the site. The procedure for doing this is summarized below.

There are four possible scenarios for estimating a free field response spectrum at a database site depending on the availability of strong-motion recordings as follows:

1. There is a recording at the database site,
2. There are one or more recordings within close proximity of the database site,
3. There are multiple recordings from the earthquake, but none are within close proximity of the database site,
4. There are none or only one or two recordings from the earthquake, and none are within close proximity of the database site.

The specific procedure for estimating a response spectrum at the database site for each of these scenarios is given below. In each procedure, the term “appropriate attenuation relationship” refers to a spectral attenuation relationship which was derived either empirically or theoretically for a region having a similar tectonic environment, similar earthquake source characteristics, and similar wave-propagation (attenuation) characteristics as the region in which the database site is located; which is applied using earthquake-specific estimates of magnitude, closest distance to the fault rupture, and style of faulting; and which represents local site conditions that are similar to those at the database site . The term “similar site conditions” refers to local soil conditions that fall into the same site classification as discussed below under Local Site Conditions.

Scenario 1. In this scenario there is a recording at the database site. In order for a recording to meet this criterion, it cannot be located any further than about two building dimensions (in plan view) from the database site facility containing the data. This recording will be used without modification to represent the response spectrum at the database site if the recording site and database site have similar site conditions. If the two sites do not have similar site conditions, the recorded response spectrum will be adjusted using the procedure described below under Local Site Conditions.

Scenario 2. In this scenario there are one or more recordings within close proximity of the database site, but none are within about two building dimensions. Whether a recording is within close proximity to the database site will depend on the distance of the recording and database sites from the earthquake rupture. In general, the distance of the recordings from the database site should not exceed about 5 kilometers (km) unless sufficient justification is given. If the distance between any recording site and the database site is a significant fraction of the distance from these two sites to the earthquake rupture (e.g., greater than about 10%), the recorded response spectrum will be adjusted using scaling factors derived from a set of appropriate attenuation relationships. If the recording site and database site do not have similar site conditions, the recorded response spectrum will be adjusted using the procedure described below under Local Site Conditions. The response spectrum at the database site will be estimated as the average of the recorded or adjusted response spectra.

Scenario 3. In this scenario there are multiple recordings from the earthquake, but none are within close proximity of the database site. In this case, the recordings are far enough away from the database site that their response spectra will need to be adjusted. This will be done by using spectral scaling factors derived from a set of appropriate attenuation relationships that have been adjusted to have the same average amplitude as the recorded response spectra. To avoid variability due to source radiation pattern and source directivity, a recording will be used only if it has an azimuth (direction with respect to the earthquake hypocenter) that is within about ±22.5 degrees of the azimuth of the database site. If less than about 5 recordings meet these criteria, Scenario 4 will be used to estimate the ground motion at the database site. If the recording site and database site do not have similar site conditions, the recorded response spectrum will be adjusted using the procedure described below under Local Site Conditions. The response spectrum at the database site will be estimated as the average of the adjusted response spectra.

Scenario 4. In this scenario, there are none or only one or two recordings from the earthquake, and none are within close proximity of the database site. In this case, a set of appropriate attenuation relationships will be used to estimate the response spectrum at the database site based on a seismological model of the earthquake. The seismological model will include an estimate of the earthquake's magnitude, seismic moment, stress drop, rupture characteristics, focal depth, and fault-rupture geometry (i.e., length, width, and dip of the earthquake rupture plane). If an appropriate set of attenuation relationships is not available, a stochastic simulation model will be used to adjust a set of attenuation relationships from another (host) region, if there is sufficient seismological data available to model the source and wave-propagation characteristics of the host and target (database site) regions. Application of the stochastic simulation model will include, in addition to those seismological parameters specified above, an estimate of the shear-wave velocity and attenuation (Q) of the hypocentral region of the earthquake and of the earth's crust between the earthquake and the database site. The response spectrum at the database site will be estimated as the mean of the response spectra derived from the adjusted attenuation relationships.

Local Site Conditions

In order for a strong-motion recording to be used in the estimation of the response spectrum at a database site, it must either: (1) be located on similar site conditions, or (2) be modified to account for the differences in these site conditions. Whether a recording site and a database site have similar site conditions will be based on a comparison of the available geological and geotechnical data that are available for the sites.

A recording and database site will be considered to have similar site conditions if they have the same Soil Profile Type as defined in the 1997 edition of the Uniform Building Code (UBC), the 1997 edition of the NEHRP Recommended Provisions for Seismic Regulations for New Buildings and Other Structures or other suitable standard, and the total depth of sediments beneath the site are sufficiently similar (i.e., within about 10% of each other). In such a case, no adjustment of the recorded response spectrum will be required. The Soil Profile Type, designated SA through SF as defined in the UBC and NEHRP Recommended Provisions, will be defined in terms of one or more of the following: (1) average shear-wave velocity, (2) average standard penetration resistance (SPT N-value), (3) average standard penetration resistance of cohesionless soil layers, and (4) average undrained shear strength of cohesive layers. In all cases, the average is taken over the top 30 meters (100 feet) of the soil profile.

Ideally, there should be sufficient geotechnical data at both the recording and database sites with which to unambiguously determine the Soil Profile Type. It is more likely, however, that there will be only general near-surface geological data at the two sites. The exceptions will be those recording sites for which special studies have been conducted to determine the lithology and/or shear-wave velocity profile at the site, and those database sites for which a geotechnical report is available. If sufficient geotechnical data are not available, general geologic descriptions from large-scale geologic maps will be used to define the Soil Profile Type using available empirical correlations between shear-wave velocity and geological information. The only time that this procedure should not be used is when a site is located in an area of complex geology where its classification in terms of a given Soil Profile Type is ambiguous. If such is the case for a recording site, the site's response spectrum will be excluded from consideration. If such is the case for the database site, the database site will be excluded from consideration until sufficiently accurate geotechnical and/or geological data can be obtained.

When an adjustment to the recorded response spectrum is required because its Soil Profile Type is different than that of the database site, this adjustment will be based on one or more of the following as appropriate: (1) empirical site factors derived from a set of appropriate spectral attenuation relationships, (2) site factors recommended in the UBC and NEHRP Recommended Provisions, and (3) other site factors derived from special empirical, theoretical or laboratory studies. When an adjustment to the recorded response spectrum is required because its sediment depth is different than that of the database site, this adjustment will be based on empirical correlations between spectral acceleration and sediment depth.

Personnel Qualifications and Independent Review

The earth-science professionals who will collect and interpret strong motion data are required to have the following minimum experience:

- Ten years of experience in the fields of earthquake seismology, engineering seismology, earthquake geology, strong-motion seismology, and/or geotechnical earthquake engineering.
- Experience in analyzing and interpreting strong-motion recordings and response spectra.
- Experience with developing and/or using strong-motion attenuation relationships.
- Experience with developing seismological models for defining earthquake rupture characteristics.
- An understanding of the impact of local soil conditions on strong-motion amplification.

The database site free field response spectrum derivation should be independently reviewed by an earth-science professional knowledgeable in ground motion estimation, and documented in accordance with Nuclear QA procedures. The independent reviewer should have the same minimum experience required by the earth-science professional who develops the ground motion estimates.

EXAMPLES

1. IBM Santa Teresa Facility HVAC (Scenario 1)

The IBM Santa Teresa Computer Facility is located in the city of San Jose in Santa Clara County, California. It is located about 12 kilometers from the surface projection of the rupture plane of the April 24, 1984 moment-magnitude (M_w) 6.2 Morgan Hill earthquake.

The Morgan Hill earthquake caused limited damage in the Morgan Hill region (Stover, 1984). It was assigned a maximum intensity of VII on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI VII were observed in Morgan Hill and southern San Jose. The Santa Teresa Facility falls within the region of MMI VII effects.

1.1 Strong-Motion Recordings

There were four strong-motion recordings at the Santa Teresa Facility (Kinemetrics, 1984). Unfortunately, the only free-field instrument at the site had a malfunction and did not produce a reliable recording. Although many publications have quoted peak accelerations from this instrument, they should be considered unreliable. The most relevant recording was from an accelerograph in the 1-story concrete HVAC building, which recorded peak ground accelerations of 0.33*g* and 0.22*g* in the East and North directions, respectively (Kinemetrics, 1984; Swan and others, 1985). The vertical channel malfunctioned so no vertical record was obtained. The 5%-damped acceleration response spectra for the two horizontal components are shown in Figure 1-1. These spectra were calculated by K. Campbell at 15 periods ranging from 0.04 to 4.0 seconds from accelerograms that he had processed while at the USGS. The original accelerograms were lost, so these are the only spectra that are currently available.

1.2 Earthquake Parameters

Eaton (1987) and Crockerham and Eaton (1987) report the following seismological parameters for the Morgan Hill earthquake:

Date:	April 24, 1984
Time:	21:15:19 Greenwich Mean Time (GMT)
Magnitude:	6.2 M_L
Epicenter:	37.309°N, 121.679°W
Depth:	8.7 km
Strike:	327° (northwest)
Dip:	84° to the northeast

Rake:	180° (strike slip)
Rupture Width:	7 km (from aftershock distribution)
Rupture Length:	25 km (from aftershock distribution

Using strong-motion and teleseismic recordings, Hartzell and Heaton (1986) determined the following rupture parameters for the earthquake:

Average Slip:	1.0 m
Seismic Moment:	2.1×10^{25} dyne-cm

The seismic moment of 2.1×10^{25} dyne-cm is consistent with a moment magnitude (M_w) of 6.2 based on the moment-magnitude relationship of Hanks and Kanamori (1979). Similar estimates of seismic moment were obtained by numerous other investigators.

The following distances from the Santa Teresa Facility to the rupture plane of the Morgan Hill earthquake were calculated from the aftershock distribution of Crockerham and Eaton:

Site	Epicentral Distance (km)	Azimuth (°)	Surface Distance (km)	Rupture Distance (km)
Santa Teresa	13.9	206	11.6	12.8

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Surface Distance is the shortest distance between the site and the surface projection of this rupture plane, and Azimuth is the angle between the epicenter and the site measured clockwise from north.

1.3 Local Site Conditions

There is no reliable site-specific geotechnical information for the IBM Santa Teresa Facility. However, a geologic map of the area (Helley and Brabb, 1971) indicates that the Facility is located on Pleistocene alluvial fan deposits. There is evidence of three periods of alluvial fan development in the southern Santa Clara Valley. The Pleistocene alluvial fans form a broad apron above the younger fans, extending to the base of the bedrock uplands that form the margins of the Santa Clara Valley. These sediments are coarser grained than those comprising the younger fans and usually display distinctive strongly developed soil profiles characterized by fragipan (hard, brittle loam) in the subsurface. This fragipan is very hard and impermeable and permits little surface water infiltration. Standard Penetration Test (SPT) resistance for the older fan deposits range from 11 ± 9 blows/ft above the fragipan to 88 ± 23 below the fragipan (Helley and Brabb, 1971). Bedrock is known to outcrop about 200 meters northwest of the site, which suggests that the Pleistocene alluvial fan deposits are relatively thin and that bedrock occurs at a relatively shallow depth beneath the Facility.

Because of the presence of the fragipan, it is difficult to classify the soil conditions at the Facility. Fortunately, this is not important since there is a recording on site. Nonetheless, the site is likely to be classified as Soil Profile Type S_C (Soft Rock and Very Dense Soil) based on the soil classification given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). This Soil Profile Type has a shear-wave velocity in the top 30 meters that ranges between 360 and 760 meters per second (m/s).

1.4 Recommended Response Spectra

The recording obtained in the 1-story HVAC building is the recommended recording for the Santa Teresa Facility. However, the building is partially buried on two sides where it is embedded into a soil berm, and its massive concrete slab and walls are likely to have attenuated high-frequency ground motion due to scattering and wave-passage effects. Therefore, it cannot be considered a free-field recording. However, it is the most reliable estimate of the ground motion to which the HVAC equipment was subjected within the building. It is, however, a conservative (i.e., lower) estimate of the free-field ground motion that occurred in the vicinity of the HVAC building. The recommended 5%-damped acceleration response spectrum is shown in Figure 1-2.

2. PALCO Cogeneration Plant (Scenario 2)

The PALCO Cogeneration Plant is located in the town of Scotia in Humboldt County, California. It is located directly over the rupture plane of the April 25, 1992 moment-magnitude (M_w) 7.0 Petrolia (Cape Mendocino) earthquake.

The Petrolia earthquake caused widespread damage throughout the Cape Mendocino region (Reagor and Brewer, 1992). It was assigned a maximum intensity of VIII on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI VIII were observed in Ferndale, Petrolia, Honeydew, Rio Dell, and Scotia. The mainshock was followed by two large aftershocks on April 26.

2.1 Strong-Motion Recordings

There was no strong-motion recording at the PALCO Plant. The closest recording to the Plant was 2.3 kilometers away at the Highway 101–Painter Street Overpass in the town of Rio Dell (CSMIP Station #89324). The geographic coordinates of the recording site are 40.503°N latitude and 124.100°W longitude. The free-field accelerograph, which is located in an instrument shelter adjacent to the bridge, recorded peak ground accelerations of 0.55*g*, 0.39*g*, and 0.20*g* in the North, West, and Vertical directions, respectively (Shakal and others, 1992). The 5%-damped acceleration response spectra for the two horizontal components (Darragh and others, 1992) are shown in Figure 2-1.

2.2 Earthquake Parameters

Oppenheimer and others (1993) report the following seismological parameters for the April 25 Petrolia mainshock:

Date:	April 25, 1992
Time:	18:06:05 Greenwich Mean Time (GMT)
Magnitude:	7.0 M_w
Epicenter:	40.332°N, 124.228°W
Depth:	10.6 km
Strike:	350° (northwest)
Dip:	13° to the northeast
Rake:	106° (predominantly thrust)

Similar source mechanisms were obtained by the U.S. Geological Survey (1992), Murray and others (1996), and Graves (1994).

Using strong-motion recordings, Graves (1994; written communication, 1994) determined the following rupture model for the earthquake:

Width (down-dip):	20 km
Length:	28 km
Depth to Top:	6.3 km
Strike:	350° (northwest)
Dip:	14° to the northeast
Rake:	90° to 105° for asperities (predominantly thrust)
	115° to 140° for shallow southern part (oblique slip)
Average Slip:	1.9 m
Seismic Moment:	2.51×10^{26} dyne-cm

The seismic moment of 2.51×10^{26} dyne-cm is consistent with a moment magnitude of 6.9 based on the moment-magnitude relationship of Hanks and Kanamori (1979).

The following distances from the PALCO and recording sites to the rupture plane of the Petrolia earthquake were calculated from the above rupture model and the epicentral coordinates determined by Oppenheimer and others:

Site	Epicentral Distance (km)	Azimuth (°)	Surface Distance (km)	Rupture Distance (km)
PALCO Plant	19.8	33	7.3	13.3
CSMIP #89324	21.9	30	7.9	13.6

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Surface Distance is the shortest distance between the site and the surface projection of this rupture plane, and Azimuth is the angle between the epicenter and the site measured clockwise from north.

2.3 Local Site Conditions

Shakal and others (1992) describe the recording site as being underlain by 15 meters of alluvium. Heuze and Swift (1991) estimate the shear-wave velocity of the soil beneath the recording site to a depth of about 10 meters to be approximately 200 m/s. There is no similar geotechnical data available for the PALCO Plant. However, a 1:62,500 scale geologic map of the area (Ogle, 1953) indicates that both sites are located on relatively thin, young (Holocene) stream terrace deposits within the Eel River Valley. The terrace deposits are composed of gravel, sand, silt, and clay, with gravel predominating. The Upper Pliocene Rio Dell Formation underlies the terrace deposits to a depth of several kilometers. Massive mudstone, alternating thin sandstone and mudstone, phantom-banded mudstone, and very fine-grained sandstone are the principal lithologic units of the Rio Dell Formation.

Based on the above information, both sites can be classified as Soil Profile Type S_D (Stiff Soil Profile) based on the site classifications given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). This Soil Profile Type has a shear-wave velocity in the top 30 meters that ranges between 180 and 360 m/s. Based on the above information, it can be concluded that both the Plant and recording sites have similar soil-amplification characteristics.

2.4 Recommended Response Spectra

Based on the proximity of the PALCO Plant to the Rio Dell recording (2.3 kilometers), the similar distance from both sites to the rupture plane of the Petrolia earthquake (13.3 and 13.6 kilometers), the similar epicentral azimuths of the two sites (30° and 33°), and the similar soil-amplification characteristics at both sites, it is believed that the Rio Dell recording can be used as a credible estimate of the ground motion at the PALCO Cogeneration Plant.

The recommended 5%-damped acceleration response spectrum is shown in Figure 2-2. This response spectrum is identical to that recommended by Boore (1997) for the same site.

3. Great Western Financial Data Center (Scenario 3)

The Great Western Financial Data Center is located in the city of Northridge in the San Fernando Valley, Los Angeles County, California. It is located directly over the rupture plane of the January 17, 1994 moment magnitude (M_w) 6.7 Northridge earthquake.

The Northridge earthquake caused widespread damage throughout the Los Angeles region (Dewey and others, 1995). It was assigned a maximum intensity of IX on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI IX were observed in Sherman Oaks, Northridge, Granada Hills, along the I-5 corridor just east of the Santa Susana Mountains, and in two neighborhoods of several blocks each in Santa Monica and west-central Los Angeles. Shaking effects consistent with MMI VIII were observed at many locations over a broad area of the San Fernando Valley, and also in parts of Santa Clarita Valley, Simi Valley, Santa Monica, west-central Los Angeles, Fillmore, the University of Southern California/County Hospital complex in Los Angeles, and in a 3-kilometer long, several blocks wide, area of Hollywood along Hollywood Boulevard.

3.1 Strong-Motion Recordings

A single strong-motion recording was obtained on the roof of the Financial Data Center. There was no ground-level recording at the Data Center. There were, however, eleven ground-level recordings within 10 kilometers of the Center. The closest three recordings are on Roscoe Boulevard in Northridge. (LA Code #C130, 2.8 kilometers), Topanga Canyon Boulevard in Canoga Park (USC #53, 5.1 kilometers), and Saticoy Street in Northridge (USC #3, 5.5 kilometers). All three recordings are located close enough to the Financial Data Center to have experienced the same level of ground shaking and earthquake source effects.

The other eight recordings that were located within 10 kilometers of the Data Center are not considered to be representative of the ground shaking at the Center for the following reasons. They were either too far from the Center (i.e., greater than 8 kilometers), they were founded on significantly different geological deposits, or they experienced significant source directivity effects. These latter effects were particularly important for recordings located northeast of the Data Center in the direction of rupture propagation (see the discussion on source characteristics below).

Darragh and others (1995) and Trifunac and others (1994) give a detailed description of the three selected recordings. A summary of this information is provided in the following table.

Parameter	LA Code #130	USC #53	USC #3
Structure	7-story bldg.	1-story bldg.	2-story bldg.
Location	Ground level	Ground level	Ground level
Latitude	34.217°N	34.212°N	34.209°N
Longitude	118.553°W	118.606°W	118.517°W
PGA (g)	0.42 (North) 0.41 (West) 0.35 (Up)	0.39 (S16W) 0.35 (S74E) 0.42 (Up)	0.45 (South) 0.33 (East) 0.80 (Up)

The two horizontal components of the 5%-damped acceleration response spectra of the three selected recordings are shown in Figures 3-1 to 3-3.

3.2 Earthquake Parameters

Scientists of the U.S. Geological Survey and the Southern California Earthquake Center (1996) report the following seismological parameters for the Northridge earthquake:

Date: January 17, 1994

Time: 12:30 Greenwich Mean Time (GMT)

Magnitude: 6.7 M_w

Epicenter: 34.209°N, 118.541°W

Depth: 19 km

Strike: 280° to 290° (northwest)

Dip: 35° to 45° to the southwest

Mechanism: Thrust

Similar source parameters were obtained by many other seismologists (e.g., *Bulletin of the Seismological Society of America*, 1996). According to these studies, the rupture initiated at the hypocenter in the southeast corner of the rupture plane and propagated up-dip to the north and northeast where the largest subevent occurred.

Using strong-motion, teleseismic, GPS, and leveling data, Wald and others (1996) determined the following rupture model for the earthquake:

Width (down-dip):	21 km
Length:	14 km
Depth to Top:	6 km
Strike:	122° (southeast)
Dip:	40° to the southwest)
Average Rake:	101° (thrust)
Average Slip:	1.3 m
Seismic moment:	$1.3 \pm 0.2 \times 10^{26}$ dyne-cm (6.7 M_w)
Avg. Stress Drop	74 bars

The seismic moment of 1.3×10^{26} dyne-cm is consistent with a moment magnitude of 6.7 based on the moment-magnitude relationship of Hanks and Kanamori (1979).

The following distances from the recording and Data Center sites to the rupture plane of the Northridge earthquake were calculated from the above rupture model and the epicentral coordinates determined by Scientists of the U.S. Geological Survey and the Southern California Earthquake Center (1996):

Site	Epicentral Distance (km)	Azimuth (°)	Surface Distance (km)	Rupture Distance (km)
Data Center	4.1	330	0.0	12.6
LA Code #C130	1.4	309	0.0	13.8
USC #53	6.0	273	1.4	15.8
USC #3	2.2	90	0.0	13.2

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Surface Distance is the shortest distance between the site and the surface projection of this rupture plane, and Azimuth is the angle between the epicenter and the site measured clockwise from north.

3.3 Local Site Conditions

There are no reliable site-specific geotechnical data available for the Financial Data Center or the three recording sites. However, a geologic map of the area (Yerkes and Campbell, 1993) indicates that the Data Center and the USC #53 site are located on Holocene alluvium up to 30-meters thick and that the LA Code #C130 and USC #3 sites are located on Late Holocene alluvium up to 3-meters thick overlain by Holocene alluvium. Since it is likely that the buildings that house the accelerographs have foundations that are at least a few meters deep, any remaining Late Holocene deposits, if present at all, are too thin to have affected the recorded ground motions at frequencies less than about 25 hertz (Hz). Underlying the Holocene alluvium is a sequence of Quaternary, Tertiary, and Cretaceous sediments at least 1 to 2 kilometers thick.

Shear-wave velocity measurements were conducted at the USC recording stations using the CXW method. This method uses surface-wave dispersion to infer the shear-wave velocity profile beneath the site. However, Boore and Brown (1998) and Wills (1998) have shown that the CXW method can lead to estimates of shear-wave velocity that are significantly different from those obtained using more traditional down-hole and cross-hole techniques. Based on this conclusion, the CXW-based measurements were not used.

Instead of relying on direct shear-wave velocity measurements, the average shear-wave velocity in the top 30 meters of the Holocene alluvium that underlies the Data Center and the three recording sites was estimated from the shear-wave velocity characteristics determined for different geologic units in California by Wills and Silva (1998). According to this assessment, all four sites can be classified as Soil Profile Type S_D (Stiff Soil Profile) based on the soil classifications given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). This Soil Profile Type has a shear-wave velocity in the top 30 meters that ranges between 180 and 360 m/s. Based on the above information, it can be concluded that the Data Center and the three recording sites have similar soil-amplification characteristics. The similarity in both the amplitude and shape of the response spectra from the three nearby recordings lends further empirical justification to this conclusion.

3.4 Recommended Response Spectrum

All of the recordings are located on the ground floor of 1-story to 7-story buildings. As a result, they are likely to be somewhat deficient in high-frequency ground motions due to wave-scattering and wave-passage effects. Further justification for these kinematic soil-structure interaction (SSI) effects can be found by comparing the response spectrum for the LA Code #C130 recording, which was obtained in a 7-story building, with the two USC recordings, which were obtained in smaller 1-story and 2-story buildings (Figure 3-4). The LA Code #C130 spectrum is found to be lower than the two USC spectra between frequencies of about 4 and 13 Hz. As a result, the selected recordings, and especially the LA Code #C130 recording, are considered to be a conservative (i.e., lower) estimate of the high-frequency amplitude of the free-field spectra at each of these sites.

The three selected recordings are all located southeast and southwest of the Financial Data Center. A contour map of the 0.24-second spectral velocity developed by the SAC Joint Venture Partnership (1995) suggests that short-period spectral amplitudes from the Northridge earthquake increased from south to north across the San Fernando Valley. This suggests that the actual ground motion at the Data Center is likely to have been somewhat higher than indicated by these recordings.

Based on the proximity of the Financial Data Center to the three selected recordings (2.8 to 5.5 kilometers), the similar distance from each of the sites to the rupture plane of the Northridge earthquake (12.6 to 15.8 kilometers), the similar location of all of the sites with respect to the rupture plane of the earthquake, the similar amplitude and spectral shapes of the three recorded response spectra (Figure 3-4), and the similar soil-amplification characteristics at each of the sites, it can be concluded that the average of the LA Code #C130, USC #3, and USC #53 response spectra can be used as a credible, although somewhat conservative (i.e., lower), estimate of the ground motion at the Great Western Financial Data Center. The recommended 5%-damped acceleration response spectrum is shown in Figure 3-5.

Boore (1997) used three entirely different recordings to estimate a response spectrum at the Financial Data Center from the Northridge earthquake. The recordings he used were from the 7-story Hotel in Van Nuys (CSMIP #24386), the Sepulveda VA Hospital in Los Angeles (USGS #637), and the Rinaldi Receiving Station in Mission Hills (LADWP SMA-1 #5968). The latter two recordings were located northeast of the Data Center in the direction of rupture propagation. As a result, the ground motion at these two sites were likely to be larger than those located closer to the Center. For example, the horizontal peak accelerations at the Sepulveda VA Hospital were 0.94*g* and 0.74*g* and those at Rinaldi Receiving Station were 0.84*g* and 0.49*g*, significantly higher than those recorded at the three sites selected in this study.

The SAC Joint Venture Partnership (1995) also estimated ground motions from the Northridge earthquake for a site very close to the Great Western Financial Data Center (their Site 4). A comparison of the recommended response spectrum in Figure 3-4 with that estimated by the SAC Joint Venture Partnership (1995) indicates that the SAC spectrum is higher, especially at high frequencies, than that recommended in this study. For example, SAC calculated peak accelerations of 0.71*g* (North) and 0.49*g* (South) for Site 4; whereas, a mean horizontal acceleration of 0.39*g* was estimated in the current study.

4. Guam Power Generating Facilities (Scenario 4)

The Guam Power Generating facilities are located on the Island of Guam, the largest and southernmost of the Marianas Island chain in the South Pacific. The island is approximately 48 kilometers long and between 6 and 19 kilometers wide. Guam is volcanic in origin. The southern end of the island is mountainous with altitudes ranging from 210 to 400 meters. The northern part of the island consists of a series of coral limestone terraces that are relatively flat and that range from about 60 to 180 meters in height.

The Guam power generating facilities consist of the Piti Power Plant and the Cabras Generating Station in the Apra Harbor area, and the Tanguisson, Yigo, and Dededo Generating Stations on the northern part of the island. According to the Earthquake Engineering Research Institute (1995), all of these facilities sustained some damage during the August 8, 1993 moment-magnitude (M_w) 7.7 Guam earthquake. The Apra Harbor facilities had the greatest amount of damage because of their location in an area of widespread ground-failure effects.

The power generating facilities are located several tens of kilometers northwest of the rupture plane of the Guam earthquake. According to the U.S. Geological Survey (1993) and the Earthquake Engineering Research Institute (1995), the earthquake caused extensive damage to hotels in the Tumon Bay area. Many structures in the Apra Harbor area were seriously damaged due to liquefaction and related ground failure. Minor damage was widespread on the island. A relatively small tsunami was generated and was noted at several locations in the South Pacific, including Japan and Hawaii, with no reported damage. The earthquake was assigned a maximum intensity of IX on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI VII were observed at several locations on the northern part of the island (U.S. Geological Survey, 1993).

4.1 Strong-Motion Recordings

The United States Navy maintained three strong-motion instruments on Guam at the time of the earthquake, but no records were recovered from these instruments because of malfunctions. However, the Earthquake Engineering Research Institute (1995) gives a qualitative estimate of the level of shaking on the island from an evaluation of liquefaction effects and damage to concrete bus stops. This evidence supports the conclusion that effective ground accelerations on the island probably ranged from about 0.15*g* to 0.25*g*.

4.2 Earthquake Parameters

The U.S. Geological Survey (1993) reports the following seismological parameters for the Guam earthquake:

Date:	August 8, 1993
Time:	08:24:25 Greenwich Mean Time (GMT)
Magnitude:	7.1 m_b, 8.0 M_s
Epicenter:	12.982°N, 144.801°E
Depth:	59 km
Strike:	255° (southwest)
Dip:	20° to the northwest
Rake:	90° (thrust)

From a complete study of P and SH body waves, Campos and others (1996) relocated the aftershocks and the subevents of the mainshock and proposed a relatively simple model for the rupture process of the event. Based on this analysis, they concluded that the earthquake ruptured a shallow-dipping thrust fault that corresponds to the subduction interface of the Pacific and Philippine Sea plates. Campos and others best single point-source model for the earthquake based on the inversion of teleseismically observed body waves is as follows:

Seismic Moment:	4.5×10^{27} dyne-cm
Centroid Depth:	41.5 km
Strike:	241.67° (southwest)
Dip:	13.77° to the northwest
Rake:	84.91° (predominantly thrust)

The moment magnitude (M_w) given by this inversion is 7.7 according to the moment-magnitude relationship of Hanks and Kanamori (1979). The fault plane solutions reported by Dziewonski and others (1994), the U.S. Geological Survey (1993), and the California Institute of Technology (Caltech) are all quite different from each other and from the solution given above. Campos and others show that their solution is statistically superior to these other solutions because they used better-constrained body-wave data.

Distances from the power generating facilities to the rupture plane of the earthquake were computed from the rupture model derived by Campos and others (1996). This rupture model indicates that the earthquake started with a small foreshock located at the hypocenter. This foreshock was about 8.6 seconds in duration and had a low rate of moment release. Then the first major subevent occurred about 30 kilometers to the northeast of the epicenter at a depth of around 46 kilometers. This was followed by a second major subevent about 12 seconds later that was located 48 kilometers to the northeast of the first subevent. The entire source-rupture process was finished in less than 32 seconds. This model indicates that 42% of the moment release occurred during the first subevent and 57% occurred during the second subevent. Campos and others give the following parameters for this rupture model:

Width (down-dip):	50 km
Length:	100 km
Centroid Depth:	46 km (first subevent); 37 km (second subevent)
Strike:	240° (southwest)
Dip:	12.5° to the northwest
Rake:	89° (thrust)
Average Slip:	2.53 m (first subevent); 3.47 m (second subevent)
Seismic Moment:	4.5×10^{27} dyne-cm
Stress Drop:	118 bars

Campos and others show that the above rupture model is consistent with the distribution of aftershocks and provides a very good fit to the coseismic displacements estimated at various locations on Guam from GPS surveys conducted before and after the earthquake by Beavan and others (1994). Campos and others also found that this rupture model was generally consistent with, but provided a better fit to the GPS displacements, than rupture models proposed by Abe (1994) and Tanioka and others (1995), which were based on an inversion of Tsunami waveforms from Japanese tidal gauge stations.

The following distances from the Tanguisson, Yigo, and Dededo facilities to the rupture plane of the Guam earthquake were calculated from the above rupture model and the epicentral coordinates determined by the U.S. Geological Survey (1993):

Site	Epicentral Distance (km)	Azimuth (°)	Energy Center Distance (km)	Rupture Distance (km)
Tanguisson	60.8	0.4	68.5	66.0
Yigo	65.1	8.9	67.3	64.1
Dededo	59.5	3.8	66.1	63.7

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Energy Center Distance is the distance from the site to the energy center of the rupture as defined by Crouse (1991), and Azimuth is the angle between the epicenter and the site measured clockwise from north.

Consistent with the definition of the energy center given by Crouse (1991), the location of this center was placed at the location of the moment centroid of the first, closest subevent. However, rather than use the independently estimated depth of this centroid, the more conservative estimate of 42.4 kilometers, which represents the projection of the subevent onto the modeled rupture plane, was preferred. Distances for the Piti and Cabras facilities were excluded from this analysis for the reasons specified below.

4.3 Local Site Conditions

The Earthquake Engineering Research Institute (1995) describes the Piti and Cabras facilities as being underlain by soft soils. The Piti facility is described as being located on loose coral fill underlain by lagoonal and estuarine deposits. The Cabras facility is reported to be founded on loose coral fill over a coral reef. The presence of soft soils and the occurrence of ground failure at the Piti and Cabras Plants indicate that they should be classified as Soil Profile Type S_F (Soft Soil Profile requiring special investigations) based on the soil classifications given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). Sites in this soil category require site-specific investigations to determine their dynamic soil-response characteristics. As a result, it is not possible to reliably estimate the ground motion at these facilities without performing a dynamic site-response analysis using site-specific geotechnical information.

There are no reliable site-specific geotechnical information for the Tanguisson, Yigo, and Dededo facilities. Instead, the local site conditions at these facilities were determined from a 1:50,000-scale geology map of Guam (Tracey and others, 1964). According to this map, the Tanguisson facility is underlain by reef facies of the Pliocene and Pleistocene Mariana Limestone. This unit is a massive, generally compact, porous and cavernous white limestone of reef origin. The Yigo site is underlain by detrital facies of the Mariana Limestone. This unit is a friable to well-cemented, coarse-to-fine grained, generally porous and cavernous white detrital limestone, mostly of lagoonal origin. The Dededo facility is underlain by the Miocene and Pliocene Barrigada Limestone. This unit is a massive, well-lithified to friable medium-to-coarse grained white foraminiferal limestone.

As reported by Dames & Moore (1994), various geophysical investigations have been performed to investigate the physical nature and configuration of the volcanic rocks and limestone on the island. Of particular interest are seismic refraction surveys and gravity surveys performed in 1982 by the Guam Environmental Protection Agency. The results of these studies indicate that the seismic velocities in the upper part of the limestone are relatively low. The surface layer of limestone, between 30 and 38 meters thick, has an average compressional-wave velocity of 945 m/s. According to Dames & Moore, this corresponds to an estimated shear-wave velocity of 460 m/s. Below the upper layer of limestone is a second limestone layer with an average compressional-wave velocity of 2,040 m/s and an estimated shear-wave velocity of 915 m/s. The volcanic basement beneath the second limestone layer has an average compressional-wave velocity of about 2,835 m/s.

The shear-wave velocity in the upper limestone layer is within the lower part of the range of shear-wave velocities (360 to 760 m/s) that are used to define Soil Profile Type S_C (Very Dense Soil and Soft Rock) in the 1997 UBC. However, considering that the shear-wave velocities reported by Dames & Moore (1994) represent an average of many measurements, it is possible that some of these sites had shear-wave velocities that fell within the upper part of the range of shear-wave velocities (180 to 360 m/s) that are used to define Soil Profile Type S_D (Stiff Soil Profile). Because of this uncertainty, it can be concluded that the Tanguisson, Yigo, and Dededo sites can be classified as either Soil Profile Types S_D or S_C.

4.4 Recommended Response Spectrum

Because of the lack of strong-motion recordings on the island, it was decided to develop a quantitative estimate of ground shaking at the Guam power generating facilities using a selected set of empirical attenuation relationships developed from worldwide strong-motion recordings of subduction earthquakes. These attenuation relationships were developed by Kawashima and others (1984, 1986), Annaka and Nozawa (1988), Crouse (1991), Dames & Moore (1994), Molas and Yamazaki (1995, 1996), and Youngs and others (1997). Each of these attenuation relationships requires a set of specific earthquake parameters in order to use them correctly. Magnitude measures include moment magnitude M_w and Japan Meteorological Agency (JMA) magnitude M_J. Distance measures include epicentral distance, closest distance to the rupture plane, and distance to the energy center of the earthquake. Also required for some relationships are the focal depth, the depth to the closest part of the fault rupture, and the type of subduction event (interplate versus intraslab).

The earthquake parameters used to estimate the ground motions from each of the attenuation relationships are given in the following table.

Parameter	Crouse	Youngs et al.	Kawashima et al.	Annaka & Nozawa	Molas & Yamazaki
Magnitude Measure	7.7 M_w	7.7 M_w	7.6 M_j	7.6 M_j	7.6 M_j
Distance Measure	Distance to Energy Center	Closest Distance to Rupture	Epicentral Distance	Closest Distance to Rupture	Closest Distance to Rupture
Focal Depth (km)	41.5	41.5	—	41.5	41.5
Source Type	—	Interface (Z_T = 0)	—	—	—
Component	Average Horizontal	Average Horizontal	Resultant Horizontal	Average Horizontal	Largest Horizontal
Site Conditions	Firm Soil & Rock	Soil & Rock	Firm Soil & Rock	V_s = 300 to 600 m/s	Hard Soil & Rock

In the above table, the value of M_w was estimated from the seismic moment of 4.5×10^{27} dyne-cm determined by Campos and others (1996) using the moment-magnitude relationship of Hanks and Kanamori (1979). The value of M_j was estimated from the average of the estimates calculated from the seismic moment versus M_j relationships published by Sato (1979) and Satoh and others (1997) using this same estimate of seismic moment. An estimate of the average horizontal component of ground motion was calculated from the amplitude of the resultant horizontal component and the largest horizontal component by applying the frequency-dependent ratios developed by Ansary and others (1995).

So as not to give undue influence to the attenuation relationships that are based solely on Japanese strong-motion recordings, the three Japanese relationships were given the same total weight as the other attenuation relationships in the calculation of the weighted average ground motion.

The estimated average horizontal value of PGA calculated from each of the five attenuation relationships for each generic site condition, along with the weighted average from the five relationships, is summarized in the following table.

Note that the range of weighted average PGA estimates (0.130*g* to 0.193*g*) is generally consistent with the range of effective accelerations estimated by the Earthquake Engineering Research Institute (1995) from an evaluation of liquefaction effects and damage to bus stops (0.15*g* to 0.25*g*).

Figures 4-1 and 4-2 show the estimated 5%-damped acceleration response spectra for the Tanguisson facility. Inspection of these figures shows that the estimated spectral accelerations on rock are lower than those on firm soil at all frequencies. Because of the uncertainty in the classification of the sites into one of the 1997 UBC Soil Profile Types,

Facility	Kawashima et al. (1/9 wgt.)	Annaka & Nozawa (1/9 wgt.)	Crouse; Dames & Moore (1/3 wgt.)	Molas & Yamazaki (1/9 wgt.)	Youngs et al. (1/3 wgt.)	Weighted Average
Tanguisson						
Rock	0.151	0.165	0.127	0.090	0.130	0.130
Firm Soil	0.195	0.165	0.216	0.095	0.208	0.187
Yigo						
Rock	0.143	0.171	0.129	0.093	0.134	0.131
Firm Soil	0.184	0.171	0.219	0.099	0.213	0.190
Dededo						
Rock	0.154	0.173	0.130	0.094	0.135	0.133
Firm Soil	0.198	0.173	0.222	0.100	0.214	0.193

the lower estimates for rock, which are consistent with Soil Profile Type S_C, were used to conservatively estimate the expected response spectrum at the three facility sites.

Because of the similarity in the estimated ground motions for the three facility sites, the empirical estimates on rock for the Tanguisson site were used as a credible, although somewhat conservative (i.e., lower), estimate of the ground motion at the Tanguisson, Yigo, and Dededo power generating facilities. The mean, 16th-percentile, and 84th-percentile empirical estimates on rock at the three sites are graphically displayed in Figure 4-3. The recommended (mean) 5%-damped acceleration response spectrum is shown in Figure 4-4. There is insufficient geotechnical information to develop recommended response spectra for the Piti and Cabras facilities.

CONCLUSION

Acceptable procedures for deriving free field response spectra for database sites for use in calculating an Earthquake Experience Spectrum (EES) for a class of equipment have been presented. Four examples have also been presented illustrating the application of the procedures for each of four scenarios. It is seen that the uncertainty in the derivation of the site response spectrum increases from Scenario 1 to Scenario 4. The conservatism in the resulting site spectrum (i.e., the likelihood that the derived spectrum underestimates the actual ground motion experienced at the site) also increases from Scenario 1 to Scenario 4 in order to account for the increasing uncertainty.

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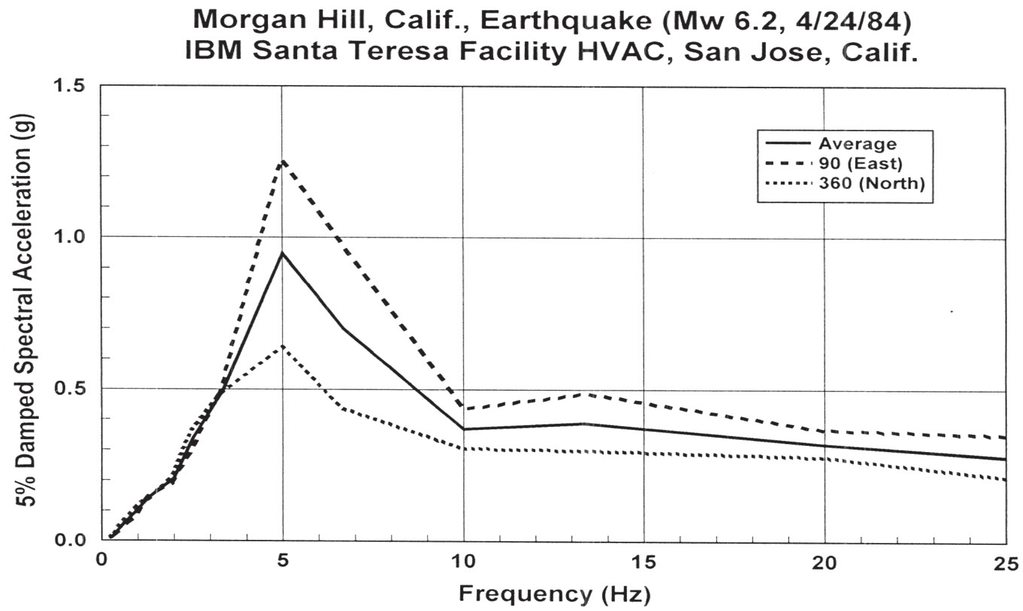

Figure 1-1. 5%-damped recorded response spectra for two horizontal components.

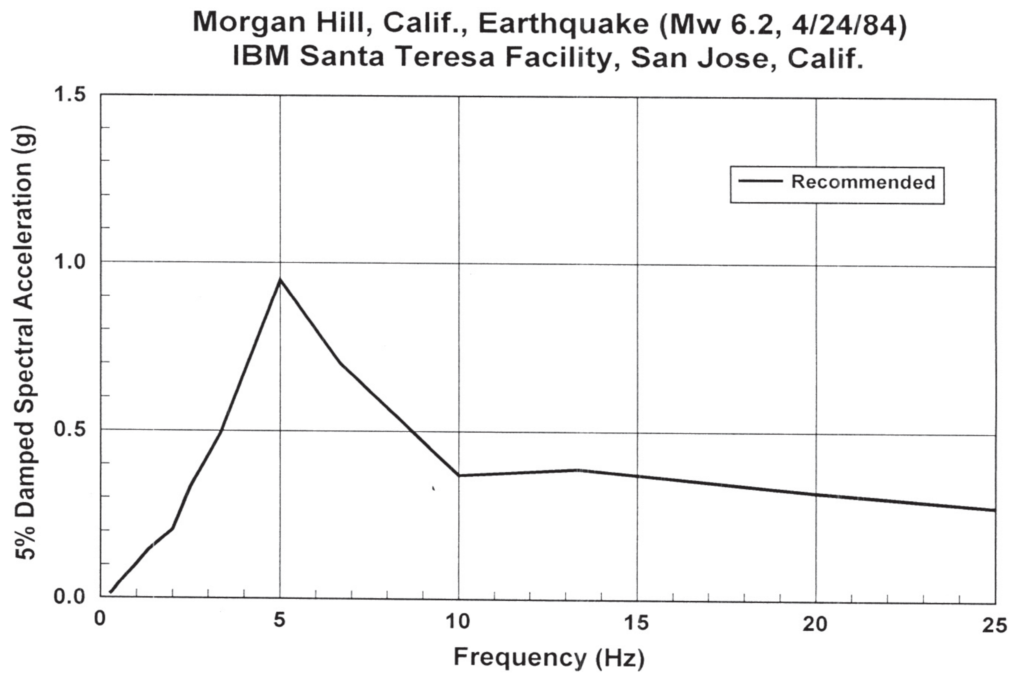

Figure 1-2. Recommended 5%-damped acceleration response spectrum.

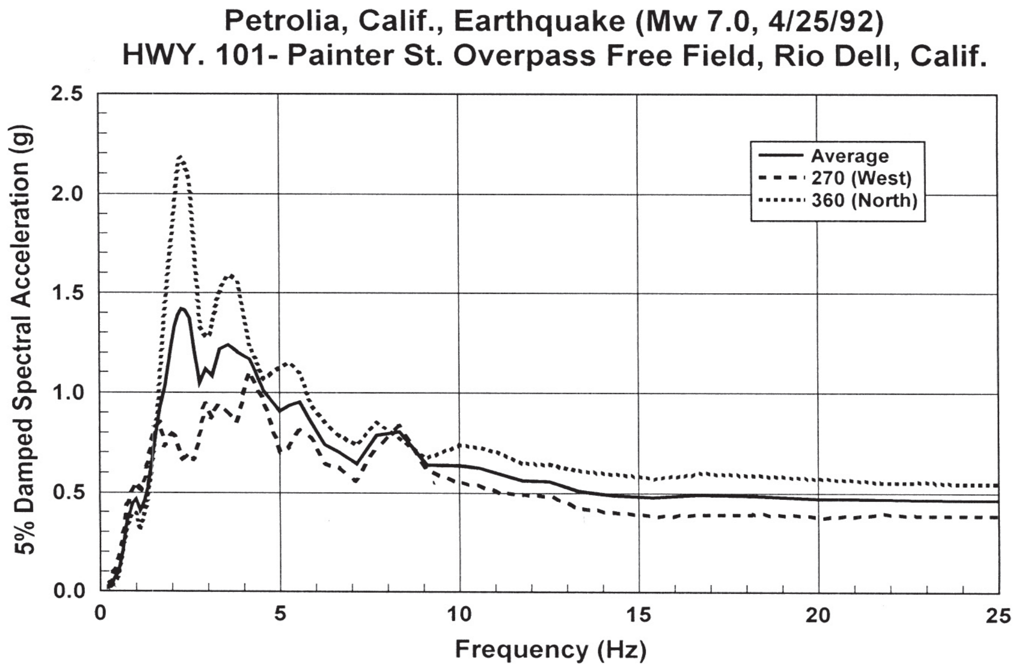

Figure 2-1. 5%-damped recorded response spectra for the two horizontal components.

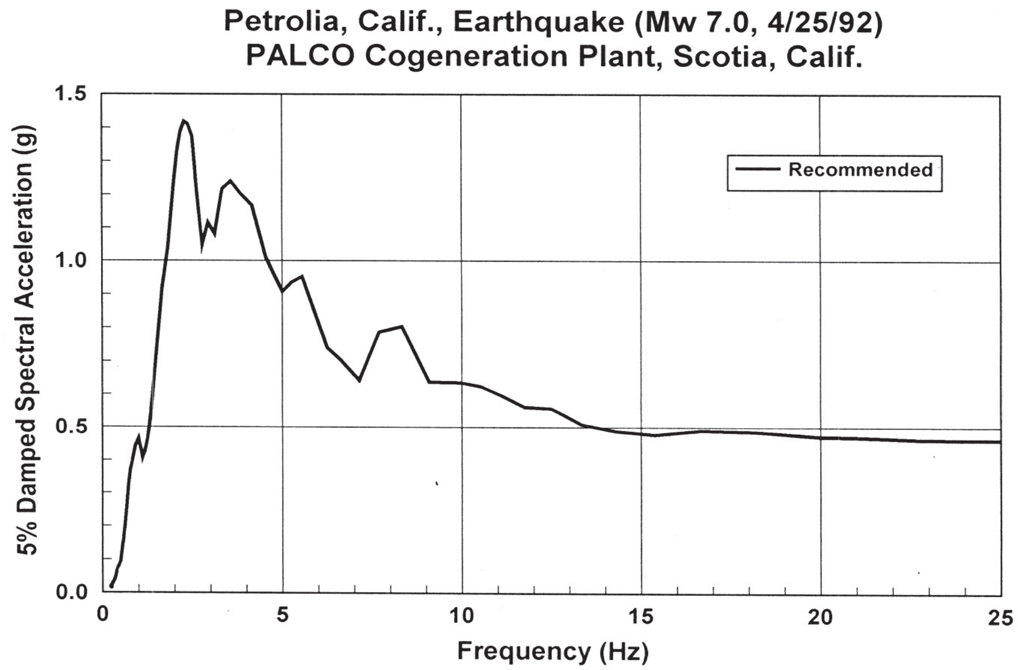

Figure 2-2. Recommended 5%-damped acceleration response spectrum.

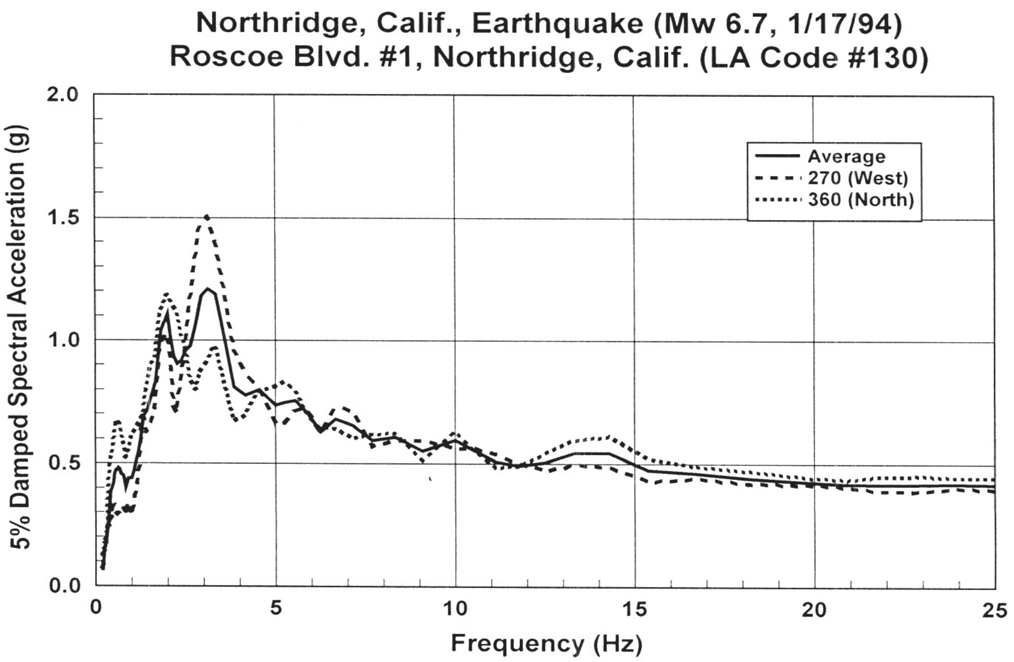

Figure 3-1. 5%-damped recorded response spectra for the two horizontal components.

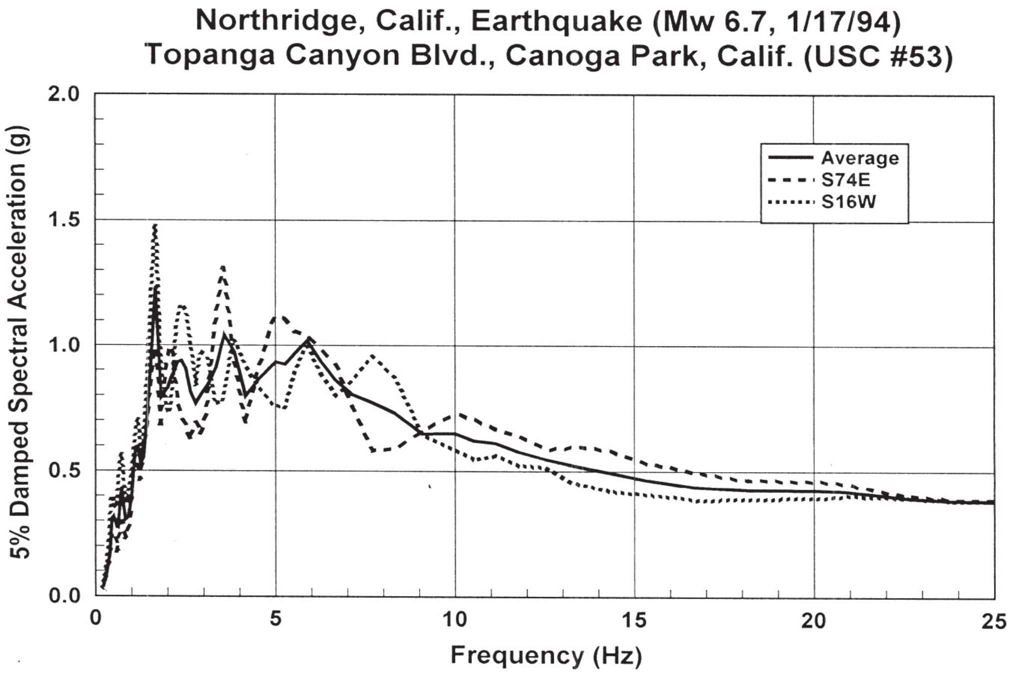

Figure 3-2. 5%-damped recorded response spectra for the two horizontal components.

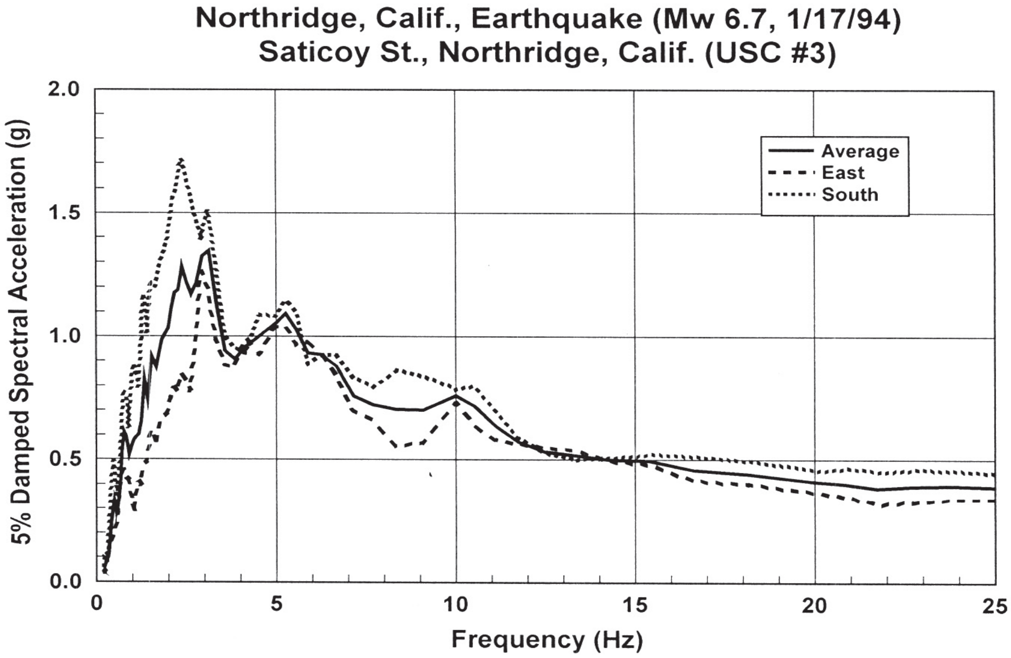

Figure 3-3. 5%-damped recorded response spectra for the two horizontal components.

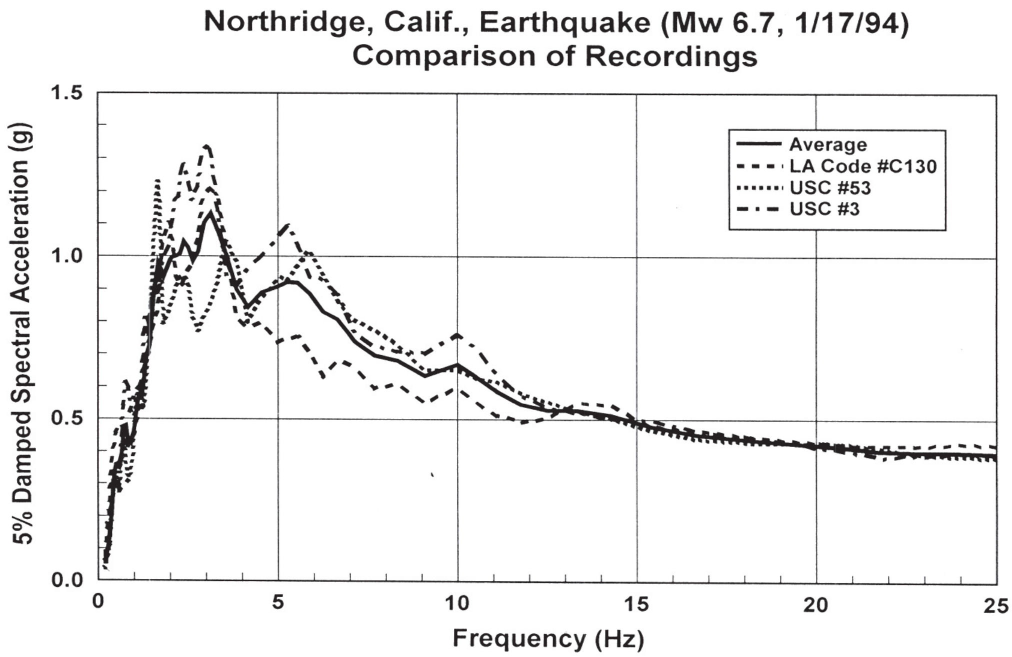

Figure 3-4. Comparison of the response spectrum for the LA Code #C130 recording, obtained in a 7-story building, with the two USC recordings, obtained in smaller 1-story and 2-story buildings.

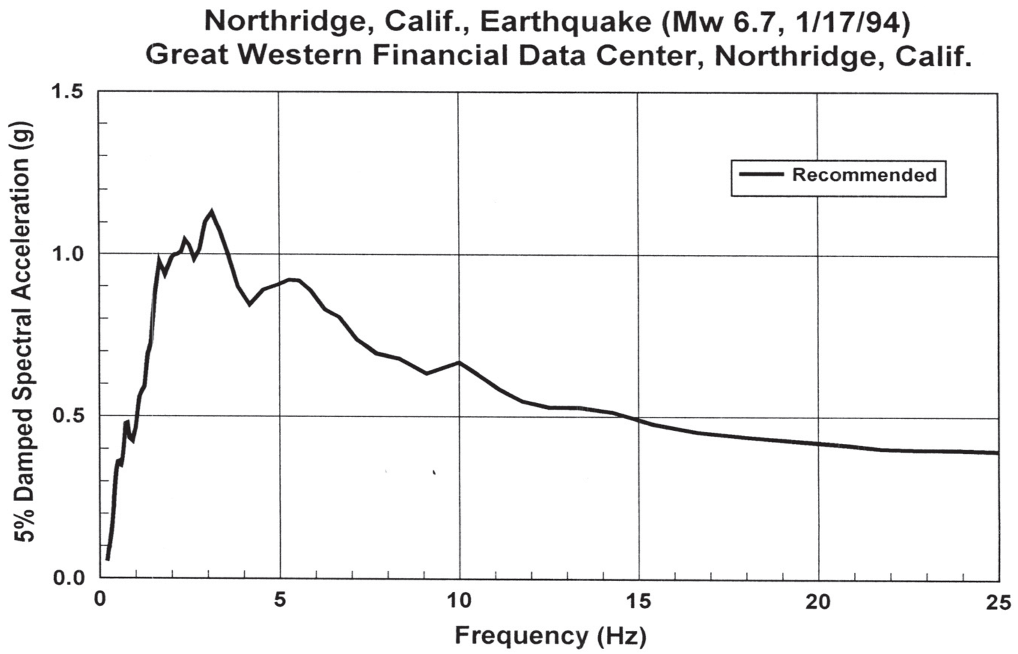

Figure 3-5. Recommended 5%-damped acceleration response spectrum.

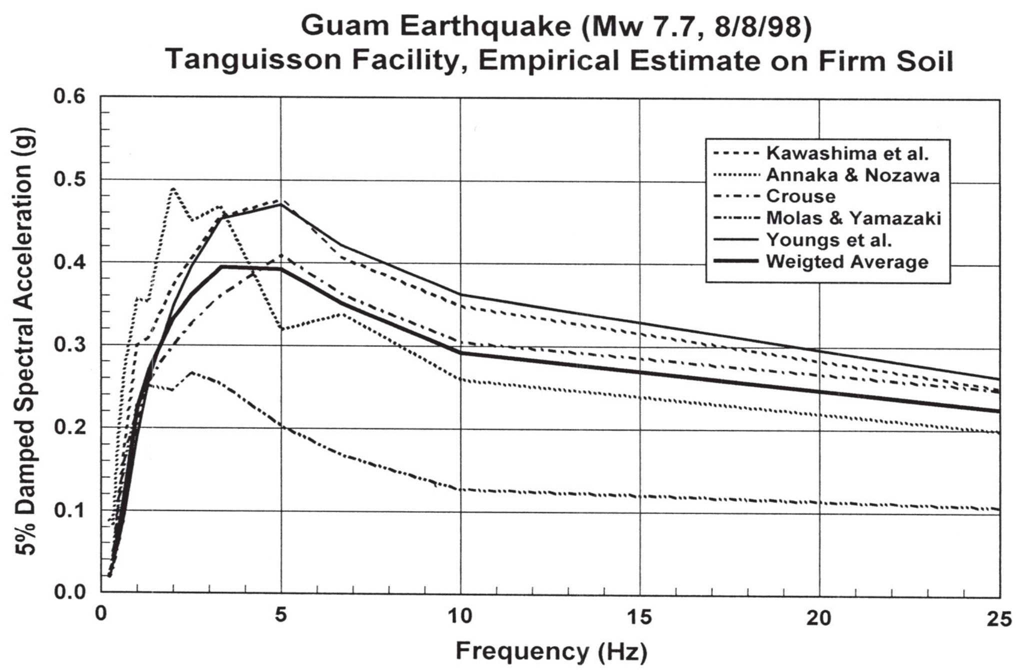

Figure 4-1. Estimated 5%-damped acceleration response spectra for the Tanguisson facility.

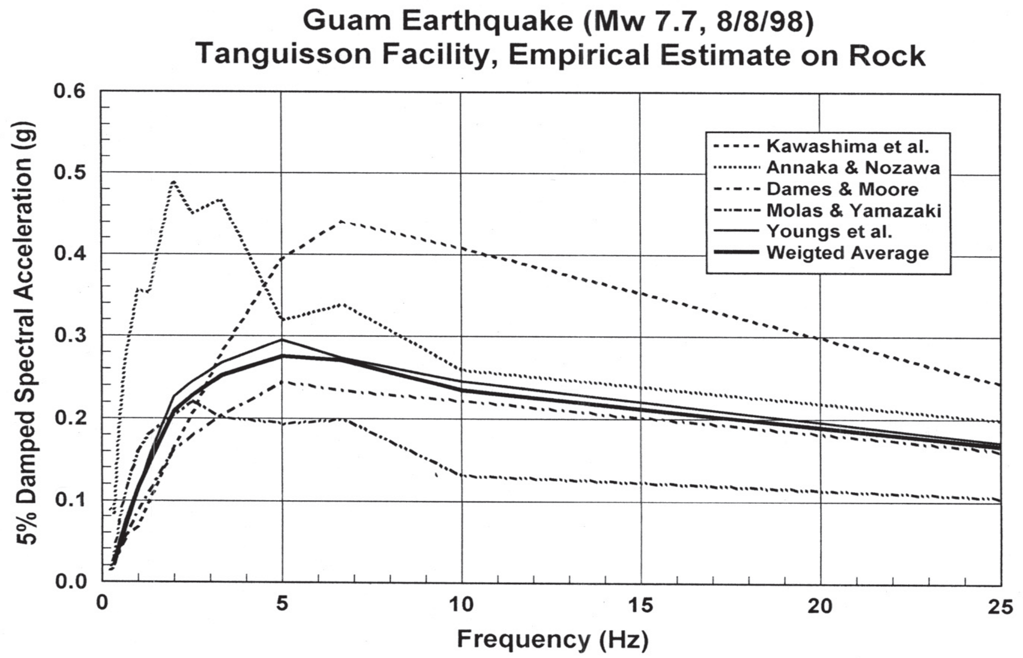

Figure 4-2. Estimated 5%-damped acceleration response spectra for the Tanguisson facility.

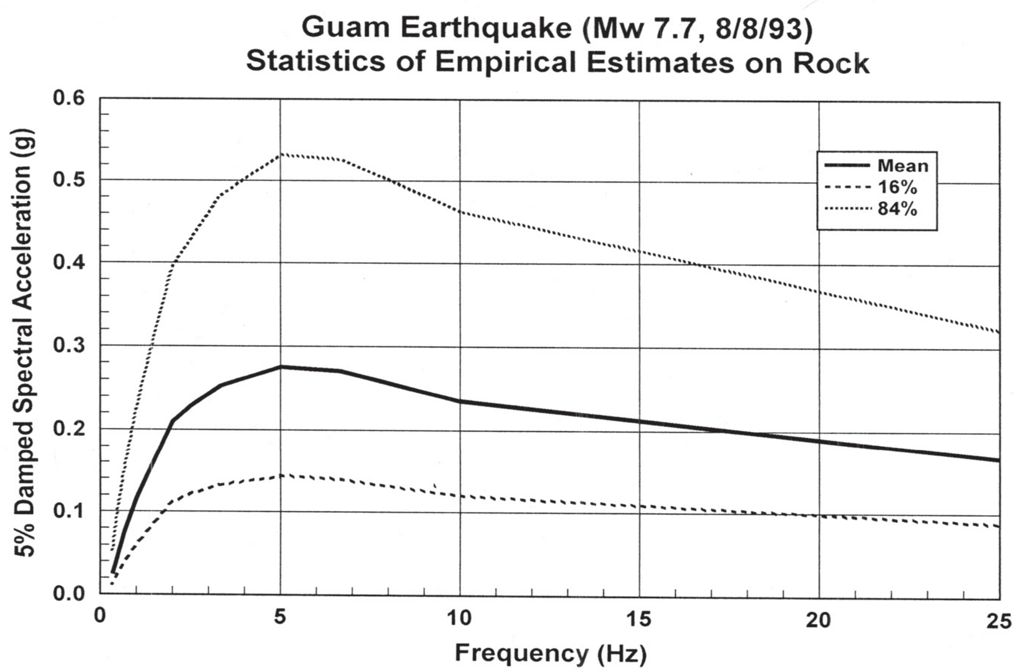

Figure 4-3. Mean, 16th-percentile, and 84th-percentile empirical estimates on rock.

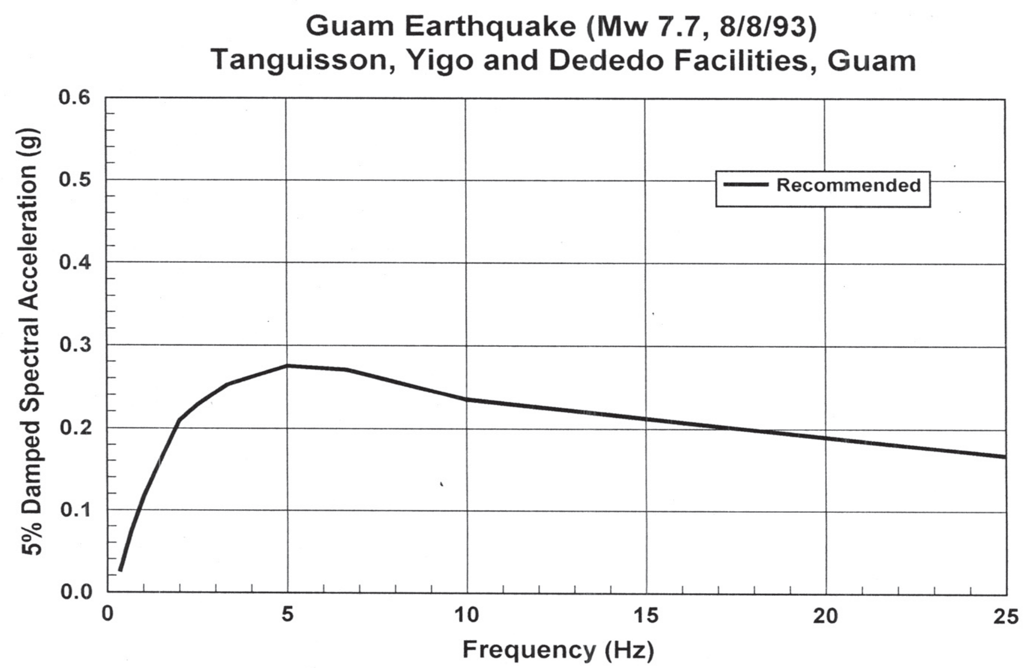

Figure 4-4. Recommended (mean) 5%-damped acceleration response spectrum.

EXPERIENCE BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

EQUIPMENT CLASS DATABASE SIZE REQUIREMENTS

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ABSTRACT

In the early 1980s the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to disposition Unresolved Safety Issue (USI) A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A-46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experience based equipment qualification could explicitly be incorporated into ASME QME-1 and IEEE-344. The joint ASME-IEEE working group concluded that experience based rules could be introduced into IEEE-344 and ASME QME-1. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ) to implement the recommendation of the joint ASME-IEEE Special Working Group. The Subgroup recently completed this effort and the QME-1 standard will include a prescriptive methodology to apply actual earthquake experience to the seismic qualification of mechanical equipment. As part of these changes, the QME-1 Standard provides requirements on equipment class database size for estimating seismic capacity based on earthquake experience data. This paper provides the technical basis for the required equipment class sample size and the associated reduction factors required for smaller sample sizes for using earthquake experience data.

Introduction

Section QR-A7422 specifies a minimum of 30 independent items that performed satisfactory to define an equipment class. Also in that section it provides Table QR-A7422-1, “Reduction Factors,” for cases where there is less than 30 independent items. Depending on the number of independent items, a reduction factor is selected per the table and then multiplied times the earthquake experience spectrum (EES) of QR-A7412 to produce an EES that has the same statistical confidence level as a reference active mechanical equipment class comprising 30 independent items. The following is the technical basis for the sample sizes and reduction factors for the number of independent items for use in estimating equipment seismic capacity using earthquake experience data.

Sample Size and Reduction Factors

Let the average spectral capacity of a given equipment class, defined as a 5% damped spectral acceleration value averaged over the 3-8 Hz frequency range, be represented by the random variable C. The distribution of C is taken as lognormal with a known (assumed) log-normal standard deviation, β_c, but an *unknown* lognormal mean, ln($\underline{C}$), where $\underline{C}$ represents the median capacity.

Let the average spectral demand that the equipment class has been subjected to, defined as a 5% damped *free-field* spectral acceleration value averaged over the 2.5-8 Hz frequency range, be represented by the random variable D. The distribution of D is taken as log-normal with a known (assumed) log-normal standard deviation, β_D, but an estimated lognormal mean, ln($\underline{D}$), where $\underline{D}$ represents the median demand.

Next consider n *independent* equipment items from the equipment class, with *known* free-field spectral demand $\{D_1,\ldots, D_i,\ldots, D_n\}$ resulting in an average *Reference Spectrum* value, D_{ave} = RS. Each of the n items has survived the respective input motion represented by D_i <u>without damage</u>. Caveats are used in defining the equipment class to exclude items with damage due to non-engineered attributes such as lack of anchorage or inadequate restraint.

The ratio of capacity to demand, C_i/D_i, for all n items is greater than unity, or

$$C_i/D_i > 1,$$

since no damage has been observed in any of the n equipment items belonging to the equipment class.

The ratio of spectral capacity to spectral demand, X = C/D, is also a lognormal variable with mean ln($\underline{X}$) = ln($\underline{C}$/$\underline{D}$) and log-normal standard deviation $\beta_X = \{(\beta_D)^2 + (\beta_C)^2\}^{1/2}$. The probability of failure for an item of equipment is given by

$$P_F = P(X<1) = F(X=1),$$

where F is the cumulative distribution function (CDF) of X.

If a reduced variate u is defined as $u = \ln(X)/\beta_X$, $u_0 = \ln(\underline{X})/\beta_X$, then

$$F(X) = \Phi(z),$$

where $z = u - u_0$ and Φ is the normal CDF. Thus,

$$P_F = F(X=1) = P(u<0) = P(z< -u_0) = \Phi(-u_0)$$

The probability of survival for an equipment item is

$$P_S = 1-P_F.$$

Now, given n pairs of independent D_i, C_i with *known* D_i and average RS but unknown C_i , apply the constraint, $X_i = C_i/D_i > 1$, since no failure has been observed in the n equipment items. If the X_i are ordered such that $X_1 < X_i < X_n$, the minimum probability of survival is given by

$$P(X_1 > 1) = \Pi_i\{1-F(X_i)\}_{Xi=1} = (1-P_F)^n.$$

Since $\underline{C}$ is unknown, it can only be specified by the assignment of a confidence coefficient. The lower confidence limit on P_F is found by considering the probability of an *assumed* failure for an (n+1)th item of equipment. This probability of failure is taken as the confidence level, γ, such that the observed result of n cases of no failure is the best that could have occurred. Thus,

$$\gamma = 1 - (1-P_F)^{n+1}$$

is the probability of failure for *at least* one item given the survival of n items.

Now the population mean, ln($\underline{X}$), which assures that, for a given level of confidence γ, the lowest capacity/demand ratio of n equipment items will be greater than unity may be estimated by requiring

$$P_F = 1- (1-\gamma)^{1/(n+1)} = \Phi(-u_0),$$

or

$$-u_0 = \Phi^{-1}\{1- (1-\gamma)^{1/(n+1)}\}.$$

Since $u_0 = \ln(\underline{X})/\beta_X$,

$$\underline{X} = \underline{C}/\underline{D} = e^{u_o\beta X}.$$

If the median demand, $\underline{D}$, is estimated as $\underline{D} = D_{ave}$ = RS, then the capacity associated with 95% confidence is given by

$$C_{95} = RS\ e^{u_o\beta X}.$$

The High Confidence Low Probability of Failure (HCLPF), or 95% confidence of less than a 5% failure probability, is given by the 5% capacity level, or

$$C_{HCLPF} = RS\ e^{u_o\beta X-1.645\beta C} = RS\ F_K.$$

where the factor $F_K = e^{u_o\beta X-1.645\beta C}$ is the reduction or knockdown factor applied to the reference capacity spectrum, i.e., EES, to achieve a HCLPF capacity value.

Taking $\beta_D = 0.3$ and $\beta_C = 0.4$ as representative lognormal standard deviations for spectral demand and capacity, then $\beta_X = 0.5$, and the following tabulation of capacity/demand ratios for a confidence coefficient γ = 0.95, or a 95% confidence level, for equipment survival is obtained for class group sizes ranging from 60 to 15.

n	P_F	$(-u_o)$	$\underline{X} = \underline{C}/\underline{D}$	F_K
60	0.047924	-1.66533	2.299	1.191
50	0.057048	-1.58005	2.203	1.141
40	0.070461	-1.47237	2.088	1.081
35	0.079847	-1.40611	2.020	1.046
30	0.092114	-1.32785	1.942	1.006
25	0.108830	-1.23277	1.852	0.959
20	0.132946	-1.11257	1.744	0.903
15	0.170750	-0.95121	1.609	0.833

A class group size of 30 is the minimum number of items necessary to demonstrate that the reference capacity spectrum, i.e., EES, without applying a reduction factor, represents a conservative estimate of the HCLPF capacity.

True Median Capacity

The development outlined above provides an estimate of the population mean, ln($\underline{C}$), which, for high levels of confidence, will be conservative (i.e., low) compared to the true population mean. The situation, as a set of n observations of no damage for the demand level recorded or estimated for each observation, may be interpreted as a sample taken from a large population of equipment meeting the attribute limits or caveats of the equipment class per QR-A7421. Estimating the *sample mean capacity*, or ln($\underline{C}$), for which the conservatism is removed would provide an estimate of the true median capacity of the equipment to be used in risk-informed seismic evaluations of equipment.

One method of achieving this capacity estimate is to consider the HCLPF values computed above, RS F_K, as one-sided lower tolerance limits based on the sample size and sample mean value. This may be represented by

$$\ln(C_{np\theta}) = \ln(\underline{C}) - k_{np\theta},$$

where $C_{np\theta}$ is the lower tolerance limit such that the probability is p that at least a proportion θ lies below $C_{np\theta}$ (or a proportion 1-θ lies above $C_{np\theta}$), and where $k_{np\theta}$ is the tolerance factor based on p, θ, and sample size, n.

In general, for the case of a known (or assumed) standard deviation (Hald, 1952),

$$k_{np\theta} = -\Phi^{-1}(\theta) + \Phi^{-1}(p)/(n)^{1/2}.$$

If p = 0.95 and θ = 0.05, and $C_{np\theta} = C_{HCLPF}$ = RS F_K, then

$$\{\underline{C}/RS)_{tol} = F_K\, e^{knp\theta},$$

and the following tabulation is obtained using the prior results for F_K:

n	F_K	$e^{knp\theta}$	$\{\underline{C}/RS)_{tol}$
60	1.191	2.102	2.503
50	1.141	2.119	2.418
40	1.081	2.142	2.317
35	1.046	2.158	2.258
30	1.006	2.177	2.190
25	0.959	2.202	2.113
20	0.903	2.237	2.021
15	0.833	2.288	1.907

Another estimate of the mean spectral capacity may be achieved by noting that the HCLPF capacity may be approximated by the 1% value ($\Phi^{-1}(0.01) = -2.326$) of capacity (Kennedy, 1999):

$$C_{HCLPF} \approx \underline{C}\, e^{-2.326\beta C}.$$

Again, let C_{HCLPF} = RS F_K. Then

$$\{\underline{C}/RS\}_{1\%} = F_K\, e^{2.326\beta C},$$

resulting in the alternate tabulation:

n	F_K	$e^{2.326\beta C}$	$\{\underline{C}/RS\}_{1\%}$
60	1.191	2.536	3.020
50	1.141	2.536	2.894
40	1.081	2.536	2.742
35	1.046	2.536	2.653
30	1.006	2.536	2.551
25	0.959	2.536	2.433
20	0.903	2.536	2.291
15	0.833	2.536	2.113

Viewing these two mean capacity estimates as upper, $\{\underline{C}/RS\}_{1\%}$, and lower, $\{\underline{C}/RS)_{tol}$, bounds, the median capacity may be estimated by the geometric average of the two bounds:

n	L=$\{\underline{C}/RS)_{tol}$	U=$\{\underline{C}/RS\}_{1\%}$	$(UL)^{1/2}$
60	2.503	3.020	2.635
50	2.418	2.894	2.525
40	2.317	2.742	2.378
35	2.258	2.653	2.321
30	2.190	2.551	2.226
25	2.113	2.433	2.183
20	2.021	2.291	2.096
15	1.907	2.113	1.990

Sensitivity to β_C

The sensitivity of β_C on the results is checked for n=30:

β_D	β_C	β_X
0.3	0.450	0.54
0.3	0.400	0.50
0.3	0.335	0.45

n	β_C	F_K	$\{\underline{C}/RS)_{tol}$	$\{\underline{C}/RS)_{1\%}$	$(UL)^{1/2}$
30	0.450	0.978	2.347	2.787	2.390
30	0.400	1.006	2.190	2.551	2.226
30	0.335	1.047	2.009	2.283	2.037

The sensitivity of the results to the uncertainty β_C is small.

Conclusion

The technical basis is provided for the minimum number of independent equipment items to define an equipment class using earthquake experience as specified in section QR-A7422 and the reduction factors, given in Table QR-A7422-1, required for reducing the EES when a smaller number of independent items are used to define an equipment class. The reduction factors per Table QA-A7422-1 are a conservative (lower) round off of the reduction factors calculated in this paper. Also, the results were shown not to be very sensitive to the assumed log-normal standard deviation of capacity.

References

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Session 3(b): Valves III

Session Chair

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Comparison of IST Conditional Monitoring Check Valve Programs to the Industry's Process Approach to Equipment Reliability

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ABSTRACT

The latest Nuclear Industry's Equipment Reliability Process and Check Valve Condition Monitoring via Appendix II of the ASME OM Code are two newly evolving approaches to improving equipment performance. Though both processes originated from separate initiatives, surprising similarities in approach and concepts are contained in each. This paper will present a comparison of the two processes and the potential advantages obtainable by a marriage of the two.

INTRODUCTION

This paper discusses the similarities of the ASME Check Valve Condition Monitoring and the Nuclear Industry's Equipment Reliability processes. It then attempts to extend these similarities to a view of a common process. It is not intended to provide a step by step strict site implementation approach, but to present a potential concept of what could be, if acted on with innovation and creativity.

OM-22 CONDITION MONITORING

Based on experiences of its members and industry, the ASME OM-22 Working Group on Check Valves, in the early '90's, began to explore alternatives to the classic prescriptive nature of ASME Codes and Standards. The current Code at the time was more directed at "failure finding" activities than the establishment of a process to insure check valve performance. Additionally the Code's prescriptive nature, dictated actions requiring expenditures of resources and station impact which did not improve performance, or allow new techniques. The prescriptive nature also did not provide the flexibility to adjust/modify its requirements due to plant design or operation, requiring of Code cases and relief requests. OM-22's work led to the conclusion that an alternative approach was advisable if these issues were to be addressed.

"Conditioning Monitoring", a process rather than a prescriptive Code, evolved from this work. By identifying the key components of a process, OM-22 found a way to ensure reliable check valve performance without dictating specific test activities or performance intervals. The results of that effort are found today in the ASME OM Code, Appendix II, "Check Valve Condition Monitoring."

Nuclear Industry's Equipment Reliability Process
Nuclear Industry has noted over the years a significant improvement in the reliability and performance of nuclear power stations, but still strives to seek further improvements. The significant benefits which could be derived from a classic organizational approach of focusing on Engineering, Maintenance and Operations had been achieved. Experience gained in assistance visits and benchmarking at both domestic and international utilities, indicated that to gain further significant improvement a different approach would be required. A focus on "process" was initiated; under this approach, all of the attributes that contribute to the success of the process are integrated regardless of what organization (i.e., Maintenance, Engineering, Operations) they are assigned to. The operation and support of a nuclear plant were divided into an integrated set of processes. Equipment Reliability process will be explored in this paper. The Equipment Reliability process focuses on maintaining a high level of safe and reliable plant operation in an efficient manner. It represents the integration and coordination of a broad range of equipment reliability activities into one process for plant personnel to evaluate important station equipment, develop long term health plans, monitor equipment performance and condition, and make continuing adjustments to preventive maintenance tasks and frequencies based on equipment operating experience. It would include activities normally associated with reliability centered maintenance (RCM), preventive maintenance (periodic, predictive, and planned), Maintenance Rule, surveillance and testing, life cycle management (LCM), planning and equipment performance, and condition monitoring. The intent was to identify, organize and integrate equipment reliability activities into a single efficient and effective process.

These two efforts, ASME's OM Appendix II and the Nuclear Industry's Equipment Reliability process, evolved from two entirely different worlds and approaches, but both shared one common focus, that of providing a process which would provide superior equipment reliability. Appendix II works in a world of regulatory requirements, while industry's processes are recommendations.

OM-22's effort involved a small group of ASME Code and check valve experts who were focused solely on check valves and Code requirements.

The Nuclear Industry's Equipment Reliability process evolved from numerous station visits/benchmarkings and involved an industry-wide experienced group whose efforts focus on a universal process involving equipment reliability of all critical station equipment.

From two such different views, the focused narrow single component vs the high level industry wide focus, the attributes which were determined to be most critical to success are remarkably common.

Fundamental to both efforts is a belief that failure of critical components is not acceptable. To OM-22 it meant that requirements which would only detect failures after they occurred would not be enough. The Industry's Equipment Reliability process establishes a policy/philosophy that "All plant equipment critical to safety and reliable generation shall be designed, maintained, and operated to ensure 'failure-free' performance."

Here are the common areas, which both efforts deemed to be critical to ensuring equipment reliability.

COMPONENT IMPORTANCE & GROUPING

Section II-2000 of the ASME OM Code requires grouping check valves by the intended purpose of the Condition Monitoring program, and the analysis of test results, maintenance history, design characteristics, application and service conditions. Owners are also required to assess the significance to plant safety if extended intervals are planned.

Industry's Equipment Reliability process initial step is the scoping and identification of Critical components taking into account critical system functions, a component's risk significance to these functions, Probabilistic Safety Analysis (PSA), and Maintenance Rule. Industry's process then under "Continuing Equipment Reliability Improvement" will develop component templates which group components based on similar service, duty, environment and design.

For both efforts an initial step is to rank components by significance. Next, components are grouped by common environment, duty and design. Done well, these groupings are fundamental for providing focus and leverage for the remaining effort. In the review of past component history, industry events, and preventive maintenance activity feedback, all information is not simply assessed against an individual component but against the group.

ANALYSIS

Section II-3000 of the ASME OM Code contains the requirements for analysis of test/maintenance history of groups to establish a basis for specific tasks. The analysis includes identification of failure modes/mechanism, determines critical failure mechanisms and determination of tasks to address or detect these identified failure modes.

Industry's process, under "Continuing Equipment Reliability Improvement", discusses an almost identical evaluation/analysis process. It identifies failure/degradation modes, and evaluates if they can be detected by Predictive Maintenance (i.e. condition monitoring) task or addressed by a PM task to control known failure due to wear/age.

EQUIPMENT RELIABILITY TASK IDENTIFICATION

Section II-4000 of the ASME OM Code utilizes the groups of valves to identify the task and task frequencies to address the analysis of failure modes provided. Tasks can include functionality tests, performance monitoring, non-intrusive Predictive Maintenance (PdM) or traditional PM. This section also requires identification of attributes that will be trended.

Industry's process, under Performance Monitoring identifies parameters, which can be monitored/trended at both a system or component level to detect performance degradation.

Industry's process, under "Continuing Equipment Reliability Improvement," performs virtually the same task that the OM Code does under section II-4000, in identifying PM and/or PdM tasks to address predominant failure modes.

ESTABLISH A LIVING PROGRAM

After the performance of each Condition Monitoring task, Section II-4000 of OM Appendix II requires a review of results to determine if changes to optimize the program are required.

Industry's process, under PM Implementation, documents the "as-found" condition at the conclusion of each PM task, and then assesses if it indicates a need to revise the program. Under Performance Monitoring, if the trending of parameters indicates performance is degrading, a similar review of the program is required.

The heavy emphasis on feedback of results and requiring that the process must be "living," in both programs, is one of the critical attributes identified which may not have been emphasized in the past.

INTEGRATION OF CORRECTIVE MAINTENANCE

Section II-5000 of OM Appendix II requires that, if corrective maintenance is performed on a check valve, that the analysis used to establish the program for that valve be reviewed to determine if changes are required.

Industry's process, under "Corrective Action," evaluates corrective maintenance and unanticipated failures to determine cause and take appropriate actions with the program to address them.

CONFIGURATION MANAGEMENT

Section II-6000 of OM Appendix II, requires documenting the rationale/basis of the program.

Industry's process calls for documentation of the critical component classification basis, performance monitoring parameter plan, and PM basis.

CURRENT PROGRAM STATUS

OM 22

Since incorporation of the option for Conditioning Monitoring into the 1996 Addenda of the ASME OM Code, and endorsement by the NRC via the Rulemaking Process, more utilities are seriously looking at revising their programs to take advantages of the efficiencies and increased equipment reliability which can be obtained. Additionally due to the new Code requirements which require bi-directional testing, Condition Monitoring is an appealing option especially for hard to test valves. Other papers including one being presented at this symposium have presented the benefits of a program transition to Appendix II Condition Monitoring. ("Enhancing your Check Valve Program by Invoking Appendix II Condition Monitoring," July, 2004, M. Robinson, NIC)

The implementation of a check valve Condition Monitoring program is typically narrow in focus and only addresses those check valves within the scope of the ASME Code. All of the Appendix II Condition Monitoring Process steps discussed above are usually addressed via a specific focused station procedure to implement solely Condition Monitoring on these ASME Code check valves. It develops steps and requirements to address each requirement of Appendix II, including assessing component significance, and analyzing component design/performance. Special steps are even taken to capture and evaluate results from planned check valve disassembles, review of Operating Experience and review of Corrective Actions. It is important to note that the focus of this entire effort is usually limited (varies between utilities) to only the ASME Code check valves.

Nuclear Industry's Equipment Reliability Process

Since creation in the late 90's, more and more utilities are embracing the Nuclear Industry's Equipment Reliability (ER) Process, driven by a desire to capture step improvement in overall equipment reliability than can be obtained by their current departmentalized approaches. Though the reliability of today's nuclear plants has significantly improved over the decade, all involved realize we can go further. With limited resources, the success being seen by the implementation of this Process (ER) by some utilities and the obvious efficiencies obtainable by changing to a focus on a process, more utilities are exploring implementation of ER Process site or fleet-wide.

Since the Process is station-wide, it requires that all of the process steps discussed above be implemented across the station. Typically a detailed evaluation of the site work process is performed to insure that the Process is effectively and efficiently incorporated. The change of focus from Departments (i.e. Maintenance, Engineering, Operations) to process, requires a change to even the culture of the station. Examples of areas which are reviewed/revised when implementing the Process station-wide are:

- Causal Determination of appropriate Corrective Maintenance actions
- Prioritization of Key Equipment Problems
- Establishment of System & Component Performance Criteria
- Aging & Obsolescence Issues
- Post Maintenance Testing
- Documentation of "As-Found" Equipment Condition from PM Tasks

A benefit of the application of the Process is in its focus on the connection and flow between the various parts of the process. Every nuclear station addresses the areas listed above, but each area was typically developed at a different time, is the responsibility of a different department, and was developed more as stand alone efforts. This process approach can focus on the linkages and flow between the areas.

A key component of the Process is the development of a component reliability plan, which is typically captured in a template. As an example of the application of the Process, a discussion will follow on how a component reliability plan (PMTemplate) was applied to Check Valves at PPL, Susquehanna. Note that an identical process was performed on other station components (i.e. fans, breakers, pumps, relays), but we will focus on Check Valves.

Development of a PM Template

- All station check valves are evaluated for component importance against a common standard used site wide to determine which valves were most critical to the safe operation and electric generation of the station
- All check valves were evaluated for duty and environment, which could impact performance
- Historical site and Industry performance experience & maintenance data was assessed
- Effective PM task, parameter monitoring, PdM tasks which address failure modes were identified
- Analysis of Information

Template development focuses on combining all information into an effective plan, which insures reliable operation, appropriate to the component's importance. Effective Component grouping is used to leverage the advantages of the process. Groupings are keyed to component importance, duty and environment under this format.

COLUMN	1	2	3	4	5	6	7	8
Component Importance Criticality	High	High	High	High	Low	Low	Low	Low
Duty/Service	High	Low	High	Low	High	Low	High	Low
Environment	Severe	Severe	Mild	Mild	Severe	Severe	Mild	Mild

Where unique performance variables are identified (i.e. unique design), new groupings are created as appropriate. A PMTemplate was developed to capture the basis of these evaluations.

A typical section of the Check Valve PMTemplate is presented below:

TITLE	PM SCOPE	PM BASIS
Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document * to insure ability to free swing, proper disk stop and side to side clearance exist	GENERIC SWING CHECK VALVE This Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ (ESW, Service Water, mud or debris carrying lines) will required increased attention particularly if internals have not been upgraded to stainless steel and are know to flutter. The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation.

The corresponding frequency related to the 1 thru 8 grouping would be as shown below:

COLUMN	1	2	3	4	5	6	7	8
FREQUENCY	RANGE 6 YEARS	RANGE 6 YEARS	RANGE 10 TO 12 YEARS RANGE (with review) 18 YEARS	RANGE 12-20 YEARS	RANGE 6 YEARS	RANGE 6 YEARS	RANGE 10 TO 20 YEARS SAMPLING TECHNIQUES MAY ALSO BE USED	RANGE 16-NEVER YEARS SAMPLING TECHNIQUES MAY ALSO BE USED

For special cases, due to past performance/reliability concerns, a unique PMTemplate task can be created, but in general it has been found that this is not necessary. When properly grouped by component criticality, environment and service, the PMTemplate provide a solid foundation for ER. NOTE: that a key component of ER, is that it is a living process, so if PM Feedback, performance monitoring, industry experience, etc, indicate improvement is advisable, a reassessment of the PM is called for. At points like this, the true benefit of the Equipment Reliability Process, becomes apparent. When data supports a review of a single PM Task, the review is not limited to the PM on that component, but expands to assess all components, which share the same component importance, environment, and duty. The assessment could determine:

That further trending and evaluation is required

Some unique characteristic of this check valve was not addressed via the current grouping, and the specific check valve is assigned to the appropriate group or a unique group is developed for this.

The assessment determines that improvements to the entire group are appropriate and the changes are applied to all check valves in the group.

At PPL, if Code requirements for forward or reverse flow testing are fully met, the ER Assessment of the check valves still compares it to the group it would be located in. If disassembly at a specified frequency is required per Industry ER process, the PM template would also be applied to the valve.

Similarly for check valves for which exception to the Code is taken and disassembles are done to comply with ASME Code, a comparison is made to what the PMTemplate group requirements would be. In most cases the Code required disassembly is at a shorter interval. This evaluation is documented and the check valves are left as unique groups.

The analysis of component performance and its associated plan are developed and documented including not only the traditional PM task, but also system and component monitoring, Predictive Maintenance and other condition monitoring tasks. Many utilities are dedicating people to focus on their PM Feedback process. PM Feedback captures the “as-found” condition of equipment during PM Tasks and the analysis/assessment of the knowledge gained against the basis and scope of the PM Task.

Typical Incorporation of IST in PMTemplate when Programs are Treated Separate

IST Reverse Flow Test	Perform Reverse Flow Test: * Isolate keep-fill source * Open test valve to drain test volume * Observe substantially restricted flow through test valve * Quantify leakage and compare to acceptance criteria or compare final pressure to initial pressure (If test media is air)	IST Program - ASME Code OMa-1988, Part 10 ASME IST Code dictates frequency.

IST Full FLOW TESTING Testing performed in conjunction with Operations SO’s	IST Program - ASME Code OMa-1988, Part 10 GL 89-04 Disassembly Group ASME IST Code dictates frequency.

COLUMN	1	2	3	4	5	6	7	8
FREQUENCY	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program

WHERE CAN ONE GO FROM HERE

Too often the advantages of combining processes are lost; one group being responsible for regulatory requirements another for preventive maintenance. By addressing the common threads of these processes, significant benefits are possible. Having demonstrated the similarities of both processes where can a station go next?

COMBINING ASME CONDITION MONITORING & INDUSTRY'S ER PROCESS

Under both programs, a common grouping philosophy can be applied. If the utility does not elect to perform a "risk ranking," it can establish a rule that all IST check valves are Critical HIGH, but the grouping will still provide a valuable function.

COLUMN	1	2	3	4	5	6	7	8
Component Importance Criticality	High IST	High IST	High IST	High IST	Low	Low	Low	Low
Duty/Service	High	Low	High	Low	High	Low	High	Low
Environment	Severe	Severe	Mild	Mild	Severe	Severe	Mild	Mild

The identification of appropriate reliability tasks and documentation can be identical for both ASME Code check valves and non-Code valves. The first step under such a combined approach would be to identify the "Right Preventive Maintenance Task at the Right Frequency." Typical tasks might be as listed below:

TASK	TITLE	PM SCOPE	PM BASIS
P	Monitor & Trend Keepfill Pressure	Isolate keepfill pressure and determine time for pressure to decay	
F	Forward Flow Verification	Monitor flow during pump operations to insure check valve opens	
T	Monitoring of Temperature	Monitor temperature downstream of check valve to detect excessive leak-by	As part of Engineering walk-down, the temperature down stream of check valve can be monitored to identify excessive leak-by. Though the task is not quantitative when excessive leak-by occurs it can be identified by this method. The ease of performance of this task to provide confidence in conjunction with other tasks warrants its use. Task is effective when downstream piping is uninsulated.
D	Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document * Insure ability to free swing, proper disk stop and side to side clearance exist	GENERIC SWING CHECK VALVE This Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ (ESW, Service Water, mud or debris carrying lines) will required increased attention particularly if internals have not been upgraded to stainless steel and are know to flutter. The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation.

This step creates initial groups based on common factors. It should not differentiate ASME Code and non-Code valves. Such groups are beneficial to the "living program" because it allows for the easy transfer of experience, improvements, and issues to address all valves regardless of their ASME Code status. For Code valves with more stringent requirements (i.e. frequency restrictions), sub tasks can be created which capture these requirements, but still allow the ability to compare all feedback and inputs to improve the reliability and performance of all valves in the overall group. See the example below, showing how Task D could be split into non-Code (D1) and Code (D2) sub tasks.

TASK	TITLE	PM SCOPE	PM BASIS
D1	Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document *to insure ability to free swing, proper disk stop and side to side clearance exist	GENERIC SWING CHECK VALVE Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ require increased attention. The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation.
D2	ASME CODE Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document *to insure ability to free swing, proper disk stop and side to side clearance exist	ASME SWING CHECK VALVE Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ require increased attention The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation. **ASME Code imposes restrictions on extension of frequency and upper limit to maximum frequency**.

Note in the example above the actual PM Task and Scope are identical. All similar valves in the station fall under Task D due to similarity. For this example, Task D applies to all normal swing check valves, which have been confirmed to demonstrate past good performance. Over 100 to 200 valves might fall under this task. The only difference, which is factored in, is the frequency restrictions of the ASME Code.

Two thoughts to keep in mind: 1) A check valve does not know as it sits in the plant, whether it is a Code valve or not. It responds to its duty and environment and the tasks that are performed on it. 2) The Station does not need to set two standards for equipment reliability, one for Code components and one for non-Code, in today's world the station demands excellent reliability from ALL critical check valves.

"LIVING PROGRAM"

ASME Condition Monitoring and Industry Process share a critical common theme, that their programs must be maintained as "living." For neither is it satisfactory to simply establish task and frequency. Both require constant feedback and trending of results to confirm the original basis for task/frequency, and to insure constant awareness of changes both from the plant and industry, that could affect the program.

If developed with an eye to the requirements of ASME OM Code Appendix II, Condition Monitoring and the recommendations of Industry process, one common efficient process can be established which meets both. Areas to address would include:

Preventive Maintenance Feedback

Operating Experience Review

Component Performance Monitoring

Corrective Action Reviews

CONCLUSION

The Nuclear Industry's Equipment Reliability Process and ASME Check Valve Condition Monitoring Appendix II strive to establish processes that ensure equipment reliability. Though Industry's focus is a station-wide approach and ASME is narrowly focused on check valves, their conclusions regarding the critical aspects of an effective program are remarkably similar. A summary comparison is proved below.

AREA	Industry ER Process	OM-22 Condition Monitoring
Program Scope	Station Wide	ASME Check Valves
Enforcement	Recommendation	Code Compliance
Identification of Component Importance	Yes	Yes
Reliance on Component Groupings	Yes	Yes
Analysis of Equipment History And Failure Modes	Yes	Yes
Identification of Task/ Monitoring to Insure Reliable Performance	Yes	Yes
Documentation of Task Basis required	Ye	Yes
Restriction on Frequency	No	Yes
Evaluate of in scope check valve failures	Yes	Yes

The lack of efficiency and cost of small focused programs can be extremely high, provide limited flexibility, and tie up critical resources. With some innovation and openness to a different approach, it appears that the marriage of the process/requirements of these two programs can produce an overall process, which is not only more cost effective and efficient, but produces even higher equipment reliability. If the Industry's ER Process is married with ASME OM Code Appendix II Condition Monitoring for all check valves, the opportunity for increased knowledge transfer and learning is created. The improvements learned from a special situation on a non-Code check valve will inherently be linked to similar Code check valves and vice versa.

If you are implementing one or both of these processes, it should be done with an eye open to encompassing the concepts offered by each of these processes in a single integrated approach.

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TRENDING CAPABILITIES OF NON-INTRUSIVE TECHNOLOGIES FOR CHECK VALVES

Nuclear Industry Check Valve Group (NIC)

Presenters:

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ABSTRACT

ASME ISTC 1995 Edition through Summer 1996, Appendix II provides an option to implement a check valve condition-monitoring program. The condition-monitoring option requires that utilities expand upon current check valve performance trending. Technologies and practices such as non-intrusive diagnostics, disassembly, and operator verification are widely used to monitor valve performance. However, most utilities only trend non-intrusive test failures since the information gathered was primarily qualitative in nature. A knowledge of which performance and functional parameters identified diagnostically that is detectable as well as trendable was required. In order to more effectively utilize available techniques, quantification of the data collected by each method that resulted in trendable information that would predict various types of valve degradation. Effective trending is expected to result in substantial reductions in both operation and maintenance costs and will allow nuclear utilities to implement ASME and Nuclear Regulatory Commission condition monitoring requirements. It was in response to this need that the Nuclear Industry Check Valve Group (NIC) initiated Phase 4 of their ongoing research program.

INTRODUCTION

The Nuclear Industry Check Valve Group (NIC), established in 1989, has facilitated a number of projects to further the reliability of check valves within the Industry. Inclusive of these projects has been an ongoing research program to investigate the capabilities of non-intrusive techniques to study check valve functional characteristics and internal conditions. The first three phases of this test program were conducted by NIC's Non-intrusive Examination Committee (NEC) during the period of 1991 – 1993. Phases 1, 2 and 3 assessed the performance of non-intrusive technologies in the three main fluid media encountered in nuclear plants – water, air, and steam, and are documented in NIC-01-Water, NIC-02-Air, and NIC-03-Steam [1,2,3]*. These previous tests established the capabilities and limitations of the non-intrusive technologies to detect valve disk position and disk motion, and to identify various degraded conditions of the valve internals. NIC's efforts resulted in widespread use of acoustics, magnetics (AC & DC), and ultrasonics for check valve testing. In 1996, the NEC prepared the Non-Intrusive Analysis Guide to provide standardized guidance on techniques of evaluating and interpreting data acquired using non-intrusive technologies. Phase 4 testing was prompted by the need to examine the trendability of non-intrusive data, acquired over time, to serve as a predictive measure of valve internal degradation.

The objective of Phase 4 is to assess the capabilities and limitations of currently available check valve testing and diagnostic methods to detect and trend valve internal conditions, quantitatively or qualitatively. The scope of Phase 4 was developed by the NEC and administered by a volunteer Technical Advisory Group (TAG) and 17 funding nuclear plants. The objective was to identify those parameters that could be trended reliably, repeatedly, and defensibly to help detect the onset of an imminent failure condition and thus constitute a basis to plan valve maintenance. This report documents the results of the first group of tests, completed in November of 2002, which examined the application of acoustics, magnetics, ultrasonics, and radiography to various types of check valves using water and air as the fluid media. This stage of testing investigated the feasibility of trending varying levels of artificially induced valve degradation that approximated the actual degradation identified in the industry through the use of commercially available non-intrusive technologies. Participation in the testing was open to the TAG and all funding utilities. Both major providers of non-intrusive diagnostic equipment and services, Crane Nuclear Services and Framatome ANP, participated. Kalsi Engineering provided the flow loop and served as independent program manager, overseeing the testing. NEC TAG-designated test coordinators provided governing oversight during the tests. NIC-04 Interim Report: November 2002 Testing was distributed to the funding utilities December 2003.

** Numbers in parenthesis denote references*

Whereas Phases 1, 2, and 3 qualified various technologies for non-intrusive testing techniques, Phase 4 aimed at extending the applicability of these technologies as well as perhaps introducing new technologies that may be used in characterizing check valve performance. Table 1.1 distinguishes the difference in scope of the Phase 1, 2 and 3 testing and the current Phase 4 testing.

EXPERIMENTAL PROGRAM

Group 1 Tests

To properly evaluate the non-intrusive techniques, a testing program was developed to evaluate the technologies under carefully controlled laboratory conditions. The flow loop comprised three parallel lines for water tests and a separate line for air tests. The scope of testing included four technologies:

- Acoustic emission
- Ultrasonic
- Eddy current
- DC magnetic

Every parameter obtained by applying each of these technologies was evaluated to determine if changes in its magnitude correlated with the level and type of artificially induced degradation. Tests were conducted at a pre-selected flow rate with an engineered upstream turbulence source that induced high levels of disk instability of the type that could lead to accelerated wear of valve internals in typical plant applications. Tests were initially conducted on a new valve to provide baseline data for comparison against subsequent parametric degradation tests.

The check valves used in this study were provided by NIC. Tests were conducted on a 6-inch stainless steel swing check valve, a 6-inch carbon steel tilt disk check valve, a 4-inch double-disk check valve, and two 2-inch stainless steel lift check valves. These valves were selected based on their availability and on the basis of how well they represented a typical range of valve sizes and valve types used in the industry. Various types and levels of degradation were induced in these valves, including; as applicable; worn hinge pin, worn stud pin, worn plug, degraded springs, etc.

Each non-intrusive diagnostic system vendor used its own proprietary standardized processes to acquire and process data. Plant experts in those specific systems to validate data collection and analysis techniques oversaw the data collection and analysis by vendors. The vendors then post-processed test results to evaluate the trendability of various non-intrusive diagnostic examination data.

	Primary Objective	Failures Modes Studies
Phases 1, 2, & 3	• Evaluate NIT technology capabilities • Verify disk stability • Verify operability – full open and full closed (Section XI)	• Stuck open • Stuck closed • Restricted motion • Detached disk • Worn internals
Phase 4	Investigate the feasibility of trending the degradation of internals to detect onset of “yellow light” failure	• Abnormal wear of hinge pin, hanger arm, plug & guide • Degraded spring • Seat leakage

Table 1.1: Scope of NIC Phase 1, 2, 3 and 4 Test Programs

Subsequent to flow loop testing all valves were shipped to TVA's Sequoyah Nuclear Station for radiographic technology evaluation.

With the baseline for reference, the five technologies were in general able to detect changes in levels of degradations qualitatively. The technologies demonstrated the ability to provide useful information about the condition of check valve internals. Once more completely understood, such trending could become a basis to detect the onset of a failure condition and provide a basis to disassemble and visually inspect valve internals provided adequate testing could be performed at the plant.

TEST RESULTS

Some Phase 4 (Group 1) test results are:

1. Demonstrated the ability of commercially available non-intrusive diagnostic systems to trend internal degradation in check valves under laboratory / controlled conditions.
2. Identified non-intrusive parameters that exhibited noticeable changes in their values in relation to changed degradation levels where others did not.
3. Assessed the capability of valve operating conditions and test scenarios to yield conclusive evidence of valve internal condition wear, etc.
4. Usage recommendations developed: e.g., reinforced the need for proper baseline data, understand test conditions and valve design.

RECOMMENDATIONS

1. The objective of Phase 4 testing was to assess the capabilities and limitation of currently available check valve testing and diagnostic methods to trend valve internal conditions. The NIC Non-intrusive Examination Committee recognized from the onset of Phase 4 that multiple sub-phases of testing and examination would be required to fully achieve this objective. The insights gained from the first series of check valve tests under Phase 4 lend credence to the NEC's conclusion that there are parameters reflective of internal conditions that can be detected and trended via non-intrusive technologies.
2. Additional testing should be performed to verify and validate conclusions reached and to build upon the insights gained from this series of tests. Continuation of Phase 4 testing, in a laboratory atmosphere, will provide the following benefits:

- Testing of numerous valve styles and sizes in a relatively short period of time,
- Finite control of internal degradations and flow parameters,
- Verification of first series (and subsequent) test results; e.g., repeatability,
- Potential refinement of existing non-intrusive technologies or development of new technologies,
- Industry-recognized processes with which individual utilities will be able to qualify non-intrusive technologies for trending of valve internal degradation.

NIC Trending Program (Phase 4)		**Group 1 Test Accomplishments**
Valve Type	**Number of Degraded Specimens Testing**	**Total Number of Tests (Tests/ Specimens x 2 Vendors)**
Swing	• 3 hinge pins • 6 hanger arm inserts • 1 hinge pin & hanger arm combo	90
Tilt	• 4 hinge pins	40
Double Disc	• 3 hinge pins • 2 springs	60
Piston 1	• 2 plugs • 3 springs	50
Piston 2 (soft seat)	• 3 plugs	30
	TOTAL	**270**
270 unique check valve flow tests performed at Kalsi Flow Loop 20+ separate Radiography tests at TVA Sequoyah Nuclear Station		

3. NIC supports the continued use of non-intrusive testing. In the early 1990s, NIC performed Phase 1, 2, & 3 studies to evaluate technologies that have been successfully and reliably demonstrated to assist in determining the operational readiness of check valves. Since then NIC has successfully continued to demonstrate, improve and refine the applications to those technologies. Detection and trending of internal degradation has been a continued open item, for which Phase 4 was implemented.

4. Participating plants should review any historical NIT data to provide input where the Phase 4 report can be validated and where it can not, based on plant data. This information could be used to determine future testing.

ACKNOWLEDGEMENTS

The NEC Technical Advisory Group (TAG), chaired by Mr. Domingo A. Cruz of Constellation Energy Group, spearheaded this project and led it from the preliminary discussion stage to completion of the first group of tests. Contributing utility TAG members were Mr. Jim Brewer of South Carolina Electric & Gas, Mr. Ivan Whitt of TXU, Mr. Ron McGuire of Tennessee Valley Authority, Mr. Ron Cameron of Constellation Energy Group, Mr. Steve Quan of Arizona Public Service, Mr. Tony Maanavi of Exelon, Mr. Roger Sagmoe of NMC, and Mr. Frank Kelly of AEP Indiana Michigan Power. Non-utility TAG members included Mr. Mike Robinson of K&M Consultants, Mr. Vinod Sharma of Kalsi Engineering, Messrs. Lew McKeague and Jason Campbell of Framatome ANP and Mr. Ernie Noviello of Crane Nuclear Services.

Mr. Sharma served as the independent project manager and provided project oversight and technical guidance. Mr. Ron McGuire and Mr. Ron Cameron served as test coordinators, assisted in keeping the testing program on schedule, and provided day-to-day coordination between Kalsi laboratory personnel, vendors, and NEC TAG members present during the tests. Messrs. Ernie Noviello, Lew McKeague, and Jason Campbell provided specialized expertise in non-intrusive data acquisition, data analysis, and technical reporting. Mr. Ron McGuire provided radiographic examination oversight and technical reporting at the Sequoyah facilities following flow loop testing at Kalsi Engineering.

Mr. Mike Robinson took the lead in ensuring that the program scope was comprehensive enough to benefit the widest set of utility needs and also in securing the crucial utility funding that made this program viable. Sincere appreciation is expressed to the following participating nuclear utilities for their financial support, without which this testing program would not have been possible:

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TVA – Sequoyah

Duke Energy – Oconee
TVA – Watts Bar

Duke Energy – McGuire
TVA – Browns Ferry

Exelon – Byron Station

NMC - Palisades

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Enhancing your Check Valve Program by invoking Appendix II Condition Monitoring

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INTRODUCTION

Have you considered going to Condition Monitoring for check valves?

Are you doing a code update in the near future or have you recently gone to a later code edition?

If you have done either and have not yet implemented Appendix II, “Check Valve Condition Monitoring Program,” then you could be missing an opportunity to reap significant benefits. Yes, those utilities who have implemented Appendix II are already seeing savings in maintenance, testing, and in man rem costs. How is this accomplished? This paper will outline the steps to take and explain the benefits that are achievable in an effort to help you make the decision to invoke Appendix II Condition Monitoring for Check Valves.

History

In the mid 1980’s, several utilities were experiencing an increase in failures of check valves. Through coordinated efforts by the Nuclear Regulatory Commission (NRC), the Electric Power Research Institute (EPRI), and the Institute for Nuclear Power Operation (INPO), studies were started to determine the causes of these failures. The following were determined to be the factors contributing to this increase in failures:

1) When the plants were designed, many of the components were purchased based on design criteria using worst case scenarios. For many of the components worst case is accident condition, and does not consider normal operating conditions. An example is Combustion Engineering designed plants, where the shut down cooling system also doubles for the low pressure safety injection system. The design criterion for shut down is approximately 1500 gpm @ 85 psig. During an accident the criteria changes to 3400 gpm @ 97 psig. As per the design specs, it is indicated that the valves for this system should be built to the accident condition. Herein lies the problem, the system sees continuous operation during shutdown in the shut down cooling mode. The actual system flow through and dp (differential pressure) across the valve is much less than design conditions. Because of this, the valve may not be reaching full open and may be unstable in the system. In other words, the valve is improperly sized. Because of this the valve may be unstable in the flow stream and degrading at an accelerated rate.
2) Another problem found was that many of the valves were placed in areas of the system where the flow may not be properly developed and uniform within the piping. Recommendations from manufacturers of the valves were not complete, or compromised due to space restrictions. A properly installed check valve should have at least ten diameters upstream and five downstream for the flow profile through the valve to be laminar. In the nuclear industry, to maintain leak tightness most plants rely on

welded rather than flanged valves to eliminate leak paths. To maintain the least amount of welding, many of these valves were placed just before or after elbows, isolation valves, control valves, pumps, and other equipment. Because of this, the valves do not see the uniform flow profiles they were designed for, and can cause an increase in failures.

3) Maintenance activities, including disassembly for Code inspections, were causing problems. Manufacturers are reluctant to give out design information which includes dimensions, tolerances, and clearances. Proprietary information is always a consideration for manufacturers when providing design information to customers. The maintenance guides and procedures supplied with the valve leave a lot to be desired. Since they give no criteria on the valve, i.e., the condition it needs to be in to be considered operational, it is difficult to determine whether or not a valve is functional when it is outside the design condition. When the utility does an inspection or maintenance they have a great chance of missing something since they have so little information. Rework and failures have increased due to improper maintenance and inspections.

4) Another problem, rapid valve closure in flowing liquid lines, may cause substantial pressure surge. In the case of check valve closure the velocity of the flowing liquid and the speed of closure are interrelated so that in many applications the fastest possible closure is desirable. The speed of closure is understood in terms of the shortest possible time following the instant of flow reversal. This follows from the consideration that the shorter the time interval can be made, the slower the velocity of the reverse flowing liquid will be.
   As in the case of shutoff valves, check valve closure can also cause downstream fluid column rupture. Under certain conditions a succession of closure "hammers" may result. In most cases it isn't that the check valve is not working correctly, but that the wrong type of check valve was installed. This has occurred more often than previously believed.

In response to such patterns in contributory factors , INPO issued Significant Operating Event Report, SOER 86-3 that directed all utilities to put into place a review of their check valves that were required for the safe shutdown and operation of the plant   and establish a living program assure that check valve failures be predicted prior to the actual occurrence. All utilities were required to respond to this SOER.

The Utility industry responded by calling for the development of a standardized guidance to be developed by EPRI and embodied in the "Applications Guide for Check Valves" (NP-5479), to provide the electric power utility industry with comprehensive and readily available information on the appropriate parameters for selection, installation, maintenance and reliable service (usage) of check valves in various nuclear power plant systems. For the purpose of definition, "usage" or "service" applies to the periods of plant operation under design conditions in which forward flow occurs through the check valve including normal (minimum through maximum flow range) conditions, as well as, upset, emergency, and faulted conditions simulated during valve tests. The major objective of the EPRI Check Valve Application Guide is to provide accurate technical guidance for utility engineers to determine if currently installed check valves are misapplied for long term reliability. The information can also be used for selecting check valves for new systems and plant modifications. The guide is intended to present information on check valve size, location, orientation, type, construction details and other parameters pertinent to valve performance. This information also enables utilities to prepare plant specific review plans and procedures in a convenient format convenient. Use of the technical information in the application guidelines is intended to improve valve reliability and in-turn improve plant availability and plant safety.

It was recognized that some existing check valve installations may not be optimal when compared with the application guidance given in this document. Also, to significantly modify the installation may not be the only alternative for appropriate corrective action.

Though the utilities followed the requirements of the SOER and the applications guide, other concerns began to arise. The first was that the formulas provided for determining the velocity required for opening and maintaining a check valve open in the stable condition need to be reviewed. The second was that the only way to really determine the condition of a check valve was to perform a disassembly and inspection. However, as described earlier, disassembly may only cause an increase in possible failures. It was obvious that a new venue was needed to answer these problems.

The industry formed the "Nuclear Industry Check Valve Group" (NIC) to provide a forum for the exchange of information and to provide a method to help in increasing the reliability of check valves. The first objective of this group was to conduct an experimental research program to investigate the ability of existing non-intrusive techniques to analyze the condition of check valves. The study included evaluating three technologies, testing eleven check valves in six different sizes, three types, and made of two different materials. The three technologies were acoustics, ultrasonics and magnetics. Each technology was evaluated to see if it could determine the position and movement of the disc and detect numerous valve degradations. Tests were performed at various flow rates and flow conditions including uniform approach flow, artificially induced turbulence, cavitation, forward flow and seat leakage. Tests were conducted with a new valve (undegraded condition) to provide baseline data for subsequent degradation tests. With the baseline data for reference, the three technologies in general were able to distinguish beyond a new valve and a valve with degraded internals. They could identify the source of the degradation and in some cases were able to distinguish the level of degradation (15 and 30 percent). They could determine if the disc was missing, stuck or operating normally throughout its entire stroke. The ultrasonic and magnetic techniques were able to determine mean disc position and identify magnitude and frequency of disc flutter. A secondary objective of the study was to collect data on the minimum velocity required to fully open (Vopen) and firmly backseat (Vmin) the check valves. These research activities were completed and the results are available through NIC.

Since then the Nuclear Industry Check Valve Group has met at least twice a year and since 1991 in conjunction with the ASME OM-22 Working Group on Check Valves so they can assist with the development of and changes being made to the Code.

The ASME OM-22 Working Group on Check Valves was formed in 1990 in part to incorporate the findings of the SOER 86-03 into Code space. It was found that the SOER program approach was more likely to identify a degraded check valve in an incipient failure condition, than the IST Code in 1990 that focused on primarily detecting a failed valve. A satisfactory IST test did not provide any additional assurance of continued reliable operation for if the valve was in a state of incipient failure it would not fail its next IST test without allowing for any preventive measures to be implemented. . The ASME OM-22 Working Group Check Valves took these things into account, and developed Appendix II "Check Valve Condition Monitoring".

The intended purpose of Condition Monitoring is improved performance, optimization of testing, and preventive maintenance activities.

A COMPARISON OF TRADITIONAL IST AND CONDITION MONITIORING

Traditional IST only takes a mere snapshot of the valve. A traditional test could only determine information that the valve would provide service in the safety direction when the test was performed. A Condition Monitoring Program would provide the information for extended performance of the valve. An example is a valve that only has a forward safety flow direction. In this case the valve under traditional IST would require only forward flow verification. This may be performed as a system flow test. In this case the disc could be missing and it would still pass. In a condition monitoring program the valve failure mechanisms would be determined, i.e. leakage, disc stud wear, sticking open, etc. Testing which would concentrate on trending towards those failures would be determined and the most cost effective test would be used. In addition to that, both directions of flow would be tested to provide assurance that in the valve being tested, the valve disc is present and that the valve is functioning, and not acting as just a piece of pipe as would have been the case in the traditional IST surveillance.

One such example is where a valve was missing its disc, though it was passing its required Code test. This valve had a requirement to only be tested in the open position and the only test being performed was a System Flow Test. Without the disc the valve had no problem passing the test.

If the valve had been tested using Appendix II it would have been required to have been tested in both directions. Also, Condition Monitoring would have developed a testing strategy requiring a baseline test with the valve in the known satisfactory condition. After that a test frequency to collect trendable data which would indicate condition would be implemented. If a trend continues to be favorable, the frequency may be stepped out (lengthened). If the trend becomes unfavorable, the test frequency would be shortened or possibly a better or more comprehensive test would be employed. Once the trend becomes negative it is time to perform maintenance prior to the valve's failure.

In a traditional program the valve is tested as part of a system rather than as a component. The traditional program does not test for specific expected failure mechanisms as in a Condition Monitoring Program. The Condition Monitoring Program determines, for each valve, the expected failure mechanism and through a process determines testing which will provide information which can be trended. In this case the valve trend provides an alert as to when maintenance is needed, not allowing the valve to go to failure.

Traditional IST does not allow for new technologies and philosophies being developed. In a Condition Monitoring Program, as technologies change and testing methods become more meaningful, utilities are allowed to incorporate improvements without relief request or prior approval. A Condition Monitoring Program requires feedback which includes reviews of past testing and methods to make sure they are meaningful. Because of this, it allows the program to be revised, as it is a living program.

Traditional IST does not allow for you to take credit for other programs or testing. Traditional IST requires a test which is set at the beginning of each update and the only way to change is through relief or to wait until the next update. In a Condition Monitoring Program you can take credit for other programs and testing being performed. If another test is developed or needed which would yield trendable results, credit can be taken for it.

In a traditional program all check valves are treated the same. A swing, piston, dual disc, etc., are all tested the same. There is no consideration as to the type of valve or its possible failure mechanisms. Condition Monitoring takes this into consideration from the beginning. It presents a more accurate picture of the valve, its application, and its history. An example is a piston check valve that has a high rate of being stuck closed in dirty water systems. In the same system, a swing check valve has only a slight chance of being stuck closed. In this case the piston check needs to be tested for this failure possibility at a greater frequency than the swing check. In a traditional program all would be tested the same. Unlike Condition Monitoring, a flexible program, Traditional IST is very prescriptive.

Benefits of going to Condition Monitoring

Condition Monitoring provides a much more meaningful testing program. As discussed previously, a Condition Monitoring Program requires testing of the condition in known wear areas of the valve which would lead to a failure. The testing, therefore, provides the most pertinent information to ensure the valve's ability to function at least until the next test interval if not further.

Probably one of the most cost effective benefits of Condition Monitoring is that it allows the utility to determine the frequency of testing based on past history (up to limits imposed by NRC). This has become even more cost effective due to other changes in the Code such as Option B for leak testing. This is an example where two programs can work together supporting each other and can save money doing so. Presently, Option B allows testing frequencies to go to a five year maximum interval and Condition Monitoring has a step wise interval extension requirement which cannot exceed ten years. Since the Option B test is a good monitor for most valve degradation the test can be performed under that program and credit can be taken for both.

In Condition Monitoring, the stepwise interval extension referenced above provides additional savings. Once a valve or group of valves has passed their test and there is no evidence of degradation, testing may be stepped out one cycle. The utility may continue to increase the interval between testing provided that the interval between testing of any individual valve does not exceed ten years as presently imposed by the NRC. With Code changes being considered, the interval is expected to be increased. The proposed change in interval will be based on refueling cycles, and will not exceed eight cycles for a group of size of 4 or more valves.

Condition Monitoring allows grouping of valves for testing. If valves are of the same size, type, and application, they can be grouped together. By doing so, the interval can be extended once a baseline condition has been established. For example, a single valve would require a baseline test and one more test at the decided time interval. If it were grouped with three similar valves once a baseline was established for each valve, one valve would be tested at the first interval, the next at the second interval, the third at the next interval, and the fourth at the next interval. This result in eight tests in the first six years of operation on an eighteen month fuel cycle compared with twelve tests in the first six years if the valves were not grouped.

The testing which is imposed in a Condition Monitoring Program determines both the valve's operational readiness if called upon, and the condition to continue to be ready until the next test interval. This testing will be more comprehensive and will determine that the valve condition is satisfactory.

A Condition Monitoring Program is a living program, not prescriptive, which can be continually updated as test results indicate, or as surveillance technologies improve. There is no requirement for relief from the program as changes occur or the industry matures. Condition Monitoring allows justification of the program and revisions at any time. As new test methods become available they can be incorporated into the program by the user.

Condition Monitoring creates a meaningful and practical solution to monitoring check valve performance.

The NRC is supportive of utilities implementing the Condition Monitoring section of the Code. This alternative has only been available since the summer of 1996, but only a few utilities have adopted it. NIC believes that all utilities might be required to implement this alternative in the future.

Presently, no relief request is required to adopt Condition Monitoring using Appendix II based on the Rule Change where a licensee's Code of record is the 1995 Edition with the 1996 Addenda or later.

TRANSITIONING TO A CONDITION MONITORING PROGRAM

Several plants with a Code of record earlier than the 1995/96 Code have requested to use Appendix II. Owners committing to Condition Monitoring are expected to receive prompt approval from the regulator. Based on the number of procedures that an Owner may need to modify, to revise their IST and Check Valve Programs, it is reasonable for Owners to request implementation over suitable time period (e.g., the process will be implemented over two year time period).

An alternative is adopting Condition Monitoring during your station's ten year Code update.

Owners should review the entire O&M Code to determine the best approach for their individual situation. This depends on the data available from their INPO Check Valve Program, their organizational structure, how much additional testing (e.g., bi-directional testing) they already perform, the interval changes available to accomplish bi-directional testing, etc.

Owners also need to be aware of the modifications in the 10 CFR 50.55 Code that modified the Appendix II requirements. This, as the process is understood, pertains to all plants, even those who obtained permission to use Appendix II via an earlier relief request that predated the November 1999 revision of 10 CFR 50.55a.

There were five issues outside of the Code change that ASME made in the1999 rule and need to be incorporated into any program. The items to be included are:

1. Bi-directional testing requirements
2. Intervals and step wise interval extensions
3. Trending
4. Safety significance
5. Discontinuation of Condition Monitoring

Before anyone can proceed, it must be decided what valves will benefit from this program. If there is previous knowledge that can be applied to the Code Program, or if the knowledge can be developed in conjunction with a corrective action program initiative, the Condition Monitoring Program provides the approved process.

With the use of Condition Monitoring, groupings provide a great benefit. Groupings are intended to allow the user to benefit from information and knowledge gained from other valves which are similar in design and exposed to the same service. Groupings will also aid in determination of the testing philosophy.

The intended purpose should be either improved performance, or optimization of testing and preventive maintenance activities.

Condition Monitoring Program Development

The first step for any program is the need to develop a procedure. The purpose of developing a procedure is to integrate control, define responsibilities, and provide process to improve and/or maintain the requisite reliability of the check valves.

Procedure:

Must define responsibilities which include but are not limited to:

- Performance
- System
- Design
- Maintenance
- Procurement
- Reliability
- Component

Define the process:

- Determine the Basis for Check Valves in the program
- Criteria for Diagnostic (i.e. Normal open / closed)
- Testing Techniques (Non-intrusive, conventional, etc.)
- Strategy
- Trending
- Reporting
- Records

Determine the benefits:

- Know the valve design / application.
- Know the failure mechanisms
- Defining the testing.
- Testing that does not allow for failure.
- Defined test frequency.
- Cost savings
  (Maintenance, Testing and Outage).

What must be committed to?

- Formal Program
- Includes all IST Check Valves
- Bi-Directional Testing
- Discontinuing requires going to code of record (‘ 95 code)
- Reviewing every two years

What must be included?

- Written Program
- Design Review is conducted
- Plant Maintenance and failure reviews get conducted
- Industry Maintenance and failure reviews get conducted
- Document the results of these reviews
- Evaluate the predictive maintenance practices
- Determine test methods
- Identify the testing and methods
- Verify the test methodology
- Determine performance / predictive testing frequency

When updating to Condition Monitoring, or at the next Code update, it is required to commit to taking your entire IST check valve population to the latest Code of record. For valves on which you do not invoke Condition Monitoring, it is required to continue the testing that is presently done, at the same frequency, and bi-directional testing of all the valves must be included at that same frequency. This may be a burden. But by putting the valves into Condition Monitoring you are still required to perform bi-directional testing, but not necessarily at the same frequency, and the prescriptive test is not required. An example is a valve for which the Code requirement includes full flow verification and a leak test. It may be a burden to verify full flow (i.e., accumulator dump valves, Safety Injection valves, etc.), and performing a full flow test on many valves provides no indication of their health. Because of this, Condition Monitoring may only require partial flow to meet the bi-directional testing requirement. This may add up to significant savings.

Current State of Condition Monitoring Programs and Actual Plant Specific Benefits and Problems

Benefits of Check Valve Condition Monitoring for Seabrook (OR09)

Summary:

- Seabrook Station has 108 valves included in the Check Valve Condition Monitoring Program.
- Condition Monitoring implemented in August, 2000 as part of the Code 10-Year Update.
- The last outage in fall of 2003, OR09 started to see the benefit with the interval extensions.
- Seabrook has aligned the Local Leak Rate Test (LLRT) testing that included check valve closure verification to the Appendix J Option B.
- Accumulator check valves do not require the accumulator “blows” since implementation of check valve condition monitoring. Positive indication of check valve opening which involves draining through the check valve is performed. This was actually an interval extension for OR09.
- Prior to check valve condition monitoring implementation, check valves on the primary side were disassembled for IST testing. These valves are now tested using alternate methods such as verification of differential pressure during various plant evolutions, tagging/draining evolutions, open verifications during plant evolutions (i.e., reactor coolant system evacuation and cavity fills), and the use of non-intrusive testing.
- Non-intrusive testing of Condensate Storage tank check valves is performed on-line and using interval extensions. Previously, valve disassembly and radiography were employed.
- The reactor coolant pump seal injection check valves are verified closed with non-intrusive testing during the outage and interval extensions have been applied. The first extension was used during OR09.

Man-hour savings:

- Approximately 900 man-hour savings for maintenance/ valve crews including scaffolding and insulation
- Approximately 380 man-hour savings for the testing group including LLRT

- Non-intrusive test engineer had a savings of 50 mrem for the outage due to the interval extensions for non-intrusive testing of the seal injection check valves

Benefits of Check Valve Condition Monitoring for McGuire (2EOC-14)

Work Hours (WH's) and dose savings for 2EOC-14 as a result of partial implementation of the Condition Monitoring Program at McGuire:

Maintenance (includes valve crews, scaffolding, and misc. tasks) 1100 man hours (based on original estimate developed in September 2001)

ALARA estimated dose savings 1154 mrem

2-4 hours of critical path time saved by not having to dump accumulators.

The above WH estimate does not include:

1) Operations (OPS) Test Group savings for elimination of acoustic testing of Cold Accumulator Check Valves, 10" cold leg primary checks, and 6" RHR checks.

2) OPS retest/functional verifications. Much of this was eliminated but no WH estimates are available.

Benefits of Check Valve Condition Monitoring for Catawba

The work hours and man rem savings were higher for Catawba Unit 1 outage with one difference. Catawba put many more valves into the program prior to the outage (118) and some were thermal reliefs that had never been bi-directionally tested. Several of these valves failed because when flow was put through the valve the soft seats (15-20 years old) partially washed out. This was expected. All of these valves were small; less than 1", and maintenance was completed quickly with no impact. The overall savings has not been documented yet is greater than McGuire's.

Benefits of Check Valve Condition Monitoring for Wolf Creek

- There are 55 valves in the Condition Monitoring Program
- Implemented in 1996 using a Relief Request.
- Benefits were found immediate upon implementation
- We have aligned the program to take advantage with other programs such as Option B Leak Testing.
- Eliminated high dose disassembly
- Reduced dose and labor associated with temporary instrumentation
- Aligned App J frequency with check valve test frequency
- Simplified bi-directional compliance
- Enabled credit for non-traditional measures (valve body wall thinning, credit for good performance, maintenance history)
- Eliminated rigid requirements to enable getting many tests off of outage critical path.
- This is an example of before and after going to Condition Monitoring Benefit:
  Auxiliary Feedwater full flow testing was performed in Mode 3 at the end of outage and set back power ascension. This test is now performed during power ascension.

Benefits of Check Valve Condition Monitoring for Millstone

There are 166 valves at Millstone Unit 3 and 117 at Millstone Unit 2 in the Condition Monitoring (CM) Program

Millstone station has adopted the 1996 code, subsection ISTC for IST check valves. The Condition Monitoring option is used on 26 valves at Unit 2, and 88 valves at Unit 3.

Benefits were first found in extended intervals for very burdensome disassembly inspections. In the last unit 2 and unit 3 outages we did not have to do some inspections and realized great savings in outage time, man-hours and man-REM.

Fewer disassemblies means lessened chance of the possibility of maintenance induced problems.

We now have better ability to align inspections with "A" or "B" train refueling outages.

The Appendix J Program, using Option B can go to 60 months in a few groups; and we use a CM evaluation to credit this testing.

We are crediting everyday operation of the plant for certain open function (bi-direction) requirements.

On-line credited surveillances and disassemblies for Condition Monitored valve groups is a great savings.

We have not reduced the number of disassemblies. We have dropped or lessened the amount of difficult disassemblies and inspections (D&I's) and added some simple, isolable, on-line D&Is. A good trade.

Millstone Units 2 and 3 will continue to dump all accumulators to credit outlet check valve strokes although we will do it at reduced pressures and less instrumentation than previous tests.

We have developed ultrasonic testing (UT) techniques to verify closure of seal injection lift check valves and some tilting disc valves.

Millstone doesn't have any figures but man-hour and man-rem savings have been realized.

Benefits of Check Valve Condition Monitoring for Byron

- The program includes all required IST Check Valves in this program, no cherry picking.
- Byron elected to go to Condition Monitoring, based on expected benefits to the station and component reliability, not as a result of the ten-year update. This was as a result of good past maintenance/diagnostic history and a solid check valve program (SOER 86-03).
- Condition Monitoring is well aligned with other programs, i.e. Option B.
- Program was implemented by June 2000-September 2001.
- There are 38 valve groupings in the program. Each group consists of 1 to 8 valves per unit, totaling 146 valves. Byron is a Two Unit, Four Loop Westinghouse pressurized water reactor (PWR).

Some examples of specific valves in the program and the benefits to the station since implementation, see below.

System	Valve ID	FREQUENCY/TEST METHOD	BENEFITS/SAVINGS
AF	1/2AF001A/B, 003A/B, 29A/B	Changed from 36-month disassembly to diagnostic surveillance on line every 36 months (per train).	Savings included maintenance /Operations (OPS)/ Radiological Protection (RP) /Scaffold. $20K Reduction of 12 hours from outage window
CS	1/2CS008A/B	Changed from 36 month disassembly to 54 month disassembly	Saving = $16K per valve which included RP/OPS/ Mechanical Maintenance (MM)/Scaffold/ Engineering
CS	1/2CS003A/B, 1/2CS011A/B, 1/2CS020A/B,	Changed frequency from 36 month disassembly, what was done to 54 month disassembly	Saving per train for 3 valves are $15K which included, RP/OPS/MM/Scaffold/ Engineering
FW	1/2FW079A-D	Tilting disc check valves were replaced with Nozzle Check at the same time that CM was implemented. Disassembly of at least one of four valves was required during each refueling with scope expansion to correct anomalous findings. Currently using diagnostics on one loop per outage.	Total cost savings after installing new valve and implementation of CM is $220K per outage. This was included cost for MM/OPS/Insulators/ Scaffold.
SI	1/2SI8948A-D 1/2SI8956A-D	Changed diagnostic testing from 4 loops to 1 loop per outage.	Savings included reduction of critical path 6 hours, which is $200K per refueling outage, Savings, including RP/MM/OPS/Insulators/ Scaffold $60K per outage
CV	1/CV8368A-D	Changed from radiography of four valves per outage to disassembly of one valve each outage	Total savings included RP/OPS/RT/Scaffold/ Insulators/Engineering is $30K per refueling outage. No longer requires 5 hours limited access to containment due to radiographic testing (RT)

Benefits of IST Check Valve Bi-directional Testing and Condition Monitoring Efforts at Palisades Nuclear Plant

- There are 25 groups and 38 valves in the Condition Monitoring Program.
- Fully implemented in 2003 using a Relief Request that was approved per NRC SER (3/1/02).
- Benefits (production costs and dose) were realized immediately upon implementation.
- We are fully integrated and aligned with the Appendix J—Option B Leak Rate Testing Program to take advantage of extended test frequencies for good performing valves (60 months versus 18 months) for exercising.
- Eliminated high dose disassembly and inspections.
- Simplified bi-directional compliance (e.g. no relief requests submitted and cold shutdown partial flow testing eliminated).
- Increased failure detection.
- Eliminated rigid exercising requirements to enable getting many tests out of outage scope and off critical path.

Check Valve / IST Program Condition Monitoring Implementation (Code Update)

The IST/CKV Program Engineers have worked together to update these two programs to the OMa-1996 Code for Check Valves, which was completed in December of ‘03. This was in response to previous check valve failures and program weaknesses. The Check Valve Program is now aligned with the best industry practices, integrates the latest and most extensive non-intrusive mythologies and techniques, and preventive maintenance activities have been optimized.

There have been extensive improvements made in the check valve program area in regards to performance and condition monitoring. Substantial savings have been realized in both operations and maintenance (O&M) and personnel dose. The EPRI Condition Monitoring Template classification and preventive maintenance (PM) guidance has also been incorporated for a blended approach to PM optimization. The condition monitoring analyses documents are complete and thorough, incorporating operating experience, maintenance and corrective action histories, and test results.

There are many more examples that could be sighted, but the bottom line is that CM has paid for itself many times over. The same methodology is also utilized on non-IST valves in the check valve program.

Conclusion

As anyone can see from the information above, invoking Appendix II “Condition Monitoring for Check Valves” will only increase a plant’s safety while saving on manpower, man-rem exposure and rad waste. Overall, plants going to condition monitoring do have some up front costs. These expenses should be able to be recovered by the first outage following implementation, if not sooner. For further information, contact any of the utilities who supported this paper or attend a meeting of the Nuclear Industry Check Valve Group, where Condition Monitoring is always discussed.

Supporting Examples:

System/Valve	Intervals and Methods	Savings and Benefits
Various Appendix J—Option B check valves	18 month exercising to 60 month exercising and leak testing. Inspection PMs aligned with 60 month LLRT to reduce number of leak tests (as-found/as-left). Non-intrusive monitoring data collected online versus outage.	No relief request needed to align good performance and exercising test frequencies Operators able to perform other work. Dose eliminated.
SIRW Tank Outlet Checks (24” swing checks on ECCS pump suction headers)	Spectacle flange not needed to be swung to align flow path. Non-intrusive testing eliminated. 10-year inspection on both valves ended. Aligned with ASME pressure test of suction piping for verifying closure with seat leakage. HPSI pump ASME test flow used for crediting open.	Eliminated 6 hours of critical path time. 40 man-hours and 400 mrem dose savings for testing portion only. One inspection takes 100s of man-hours and dose.
Containment Sump Check Valves (24” tilting disc checks on ECCS pump suction headers)	Manual Exercise test with torque wrench was used to measure breakaway. Breakaway test results were not repeatable. Changed to measure shaft rotation and torque using air-operated valve diagnostic equipment under CM. Once repeatability is established using this new methodology, then test intervals will be extended.	CM allowed a tailored test methodology to be developed employed. This saved a relief request from being developed and approved.
ECCS Pump Suction and Discharge Checks	Trains aligned to test one valve per outage during full flow (most repeatable test conditions) using non-intrusive techniques. Note: Partial flow tests were maintained quarterly so as not to impact PSA Model/Risk Ranking.	Initial interval established under CM for non-intrusive testing (NIT) is 3 years (changed from 18 months). Next interval change should go to six years or better. Inspection PM activities were deleted.

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Experimental Investigation of Swing Check Valve Performance

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Abstract

In spite of its simple design, structure and operating mechanism, a swing check valve is one of the critical components which adversely affect the safety of the nuclear power plants if they fail to function properly. Therefore, it is important to evaluate the performance condition of the swing check valves in safety-related systems, where the opening characteristics and the minimum flow velocity are major factors to identify the performance of a swing check valve. The minimum flow velocity necessary to just open the disc at a full open position is referred to as V_{OPEN}, but V_{MIN} is defined as the minimum velocity to fully open the disc and hold it without motion.

In the present study, the existing minimum velocity model for a swing check valve is modified by considering four different forces acting on the disc such as back seating force at the full open position, weight of the disc assembly, flow inertia, and pressure differential forces. This model can also predict the position of the disc for a given average flow velocity. For verifying the present model, an experimental loop is designed and installed to measure the disc positions with flow velocity, V_{OPEN} and V_{MIN} for 3-inch and 6-inch swing check valves. The tests were performed at various conditions of upstream flow disturbance source and distance from the tested check valves. These experimental results are presented and compared with the model predictions.

Introduction

Check valves have been used in many pipeline systems throughout nuclear power plants and play an important role in the operations and protection of plant components and systems. The functions of a check valve are to prevent flow reversal in a piping system due to the shutdown of a pump or the closure of a control valve, and to allow forward flow in response to flow direction. So, check valves have been considered to be the simple and passive component requiring no further concern till quite recently. In addition, the minimum flow velocity required to open the disc fully and thus prevent motion (V_{MIN}) is sometimes ignored. However, check valves must operate properly and reliably when called upon to perform their design function. Also, one important lesson learned in the industry is that valves of similar design may have exceedingly different performance characteristics. Thus, check valves have been the subject of investigation and testing for a number of years.

Chiu and Kalsi [1] developed the theoretical model for determining V_{OPEN} velocity. They used the simple moment balance equation about the disc hinge of a swing check valve but the forces necessary to hold the disc without motion were not considered in the model though they introduced the seating force margin of 20% to consider the effects of turbulence fluctuation and upstream flow disturbances. This margin leads about 10% higher value than V_{OPEN}.

To derive the V_{MIN} velocity, Rahmeyer [2] considered four different forces acting on the disc such as back seating force of the valve body against the fully open disc, disc assembly weight, flow inertia and pressure differential force. However, he combined the pressure differential and the back seating forces into a single moment using a coefficient for pressure drop and backseat forces. Also, it is recommended to improve or adjust his model to consider the effects of the upstream flow disturbances on the V_{MIN}. These models are included in EPRI report [3] as V_{OPEN} and V_{MIN} equations, respectively.

The conditions at which the disc of a swing check valve opens fully are directly related to the velocity of the upstream flow. For example, the upstream piping components such as valves, elbows, reducers, and expansions modify the flow profile approaching the valve, resulting in the change of the relationship between the flow rate and the position of valve disc. Even at high flow velocities, upstream conditions that cause the disc not to open fully may exist, but those conditions are often overlooked.

In this paper, the existing model to predict the minimum required velocity and the valve positions with the average flow velocity for a swing check valve is modified and the experimental loop to measure the disc positions with flow velocity, V_{OPEN} and V_{MIN} will be described. These experimental results are also presented to compare with the model predictions.

Analysis

Background

The movement of the valve disc depends on the hydraulic forces, disc weight, valve hinge friction force, inertia, and any external forces if they exist. In general the effects of the disc inertia, disc weight and the external forces are describable in a straightforward way. However, the friction induced at the hinge is difficult to evaluate but its effect is usually not significant. Rahmeyer suggested that any friction of the valve hinge would be negligible in his experiments on large-size check valves [2]. The hydraulic force plays the most significant role in determining the valve behavior, including disc opening performance. But the hydraulic force historically has not been characterized properly.

The hydraulic force is the force due to the fluid flow around the disc of a swing check valve. Theoretically, the hydraulic force can be calculated from the pressure distribution around the valve disc. However, it is nearly impossible to determine the pressure distribution analytically or experimentally due to complicated flow patterns. As an approximation, the hydraulic force is often estimated by the difference of pressure measured at two locations across the check valve where steady one-dimensional flow assumption dominates.

The hydraulic force has been described in three categories by previous investigator [2, 4-7]: pressure difference across check valves; relative motion between the fluid flow and the disc rotation; and both of two components. Rahmeyer [2] assumed that the hydraulic force is composed of two terms attributable to flow velocity and pressure difference, respectively. He determines the coefficients to quantify the hydraulic moment by measuring the valve discharges but the pressure drop coefficient is considered as a constant. Botros et al. [4] applied this approach to a check valve in gas flow with some modifications. Uram [5] estimated hydraulic force by the difference of pressure measured across the check valve. Both Pool et al. [6] and Ellis and Mualla [7] represented the hydraulic force as two terms of flow and damping. They used a similar approach to determine both the flow and damping coefficients. The flow coefficient was determined experimentally from a steady state flow test and the damping coefficient by free movement of the disc in initially still water.

Modeling

In this study, the similar approach to Rahmeyer's one is taken. It is assumed that the hinge friction force is negligible and the flow in the pipe is fully developed. Thus, the forces acting on the check valve disc are due to: the submerged weight of the disc assembly; the flow around the valve disc; the pressure differential across the valve and disc; and back seating forces of the valve body against the fully open disc.

As shown in Fig. 1, the disc assembly weight and the back seating force exert a closure torque for the horizontal orientation. On the other hand, the fluid and pressure differential forces exert a torque in a direction to open the disc. Therefore, the position of the check valve disc at any time, evaluated as the angle of the disc from vertical, may be found using a balance of those four forces acting on the valve assembly. By balancing torques about the axis through the center of the disc, the velocity required to maintain the disc position without motion at a full open angle can be expressed by:

$$V = \sqrt{\frac{M_{WT}/\rho}{\frac{\pi}{4}\cdot K_{VEL} + K^*_{\Delta P} - K_{SEAT}}} \qquad (1)$$

where the definitions of M_{WT} and K_{VEL} are the same as in Reference 2, as shown in Table 1. The parameter $K^*_{\Delta P}$ is the torque parameter only due to the pressure differential force across the disc:

$$K^*_{\Delta P} = \frac{1}{2}\cdot C_D \cdot A_D \cdot L \qquad (2)$$

where C_D is the disc pressure drop coefficient, A_D is the disc area, and L is the length from the hinge pin to the center of the disc. Note that $K_{\Delta P}$ in Rahmeyer's model is the combining torque parameter due to the pressure differential and the backseating forces as follows:

$$\begin{aligned} K_{\Delta P} &= A_D \cdot L \cdot C_D \\ &\cong A_D \cdot L \cdot (K_b \cdot \theta)^{-3} \end{aligned} \qquad (3)$$

where K_b is the coefficient for the pressure differential and back seating forces.

In Eq. (1), K_{SEAT} is the torque parameter due to the back seating forces of the valve.

$$K_{SEAT} = C_{SEAT} \cdot W_{DISC} \cdot (L/D_i)^2 \qquad (4)$$

where W_{DISC} is the weight of the disc, D_i is the inside diameter of the valve inlet, and the back seating coefficient C_{SEAT} is as follows:

$$C_{SEAT} = \frac{0.065 \cdot (\Delta\theta)^2}{\rho \cdot g} \qquad (5)$$

Equations (4) & (5) results from the assumption that the torque due to the back seating force is the same as the kinetic energy of the valve disc at the full open position. The basis of this assumption is that the additional torque, required to maintain the position without motion after the valve fully opens, approximates the kinetic energy due to the disc tapping at the full opening position. To obtain the disc velocity, the natural frequency of the disc is needed. The disc natural frequency can be approximated as twice of the turbulent eddy frequency:

$$f_{EDDY} = 0.08 \cdot V / D_i \qquad (6)$$

from the suggestion by Griffith and Sununu [8]. Then we can determine the disc velocity V_{DISC} using the following equation:

$$V_{DISC} = L \cdot \Delta\theta \cdot (2 \cdot \pi \cdot f_{EDDY}) \qquad (7)$$

from which the kinetic energy of the disc at the full open position, and therefore the expressions of Eqs. (4) and (5), can be obtained.

When using the Eq. (1) to obtain the disc position at a fluid velocity, K_{SEAT} is zero. If we want to determine V_{MIN}, however, Eq.(4) should be used to calculate K_{SEAT}.

Experiments

Experimental Loop

As shown in Fig. 2, a check valve performance test loop with two horizontal 3-inch and 6-inch test sections was designed and constructed for this study. Figures 3 and 4 are the photographs of the experimental loop and two swing check valves with instruments for the test, respectively.

The main components of the loop are two water storage tanks, centrifugal pump with rated capacity of 5.4 cubic meters per minute (m^3/min) at 71.35 meters (m), two flow meters, test section, and flow control valves, including the several pipe segments. The capacity of each storage tank is 2 m^3, and the pump is driven by an electric motor.

The test section is of modular construction, allowing piping configuration changes for upstream flow disturbance testing. For the tests, the type of the disturbance sources, such as elbow and globe valve, and the position of the 3-inch or 6-inch swing check valves in the test section can be adjusted. The main pipes have an inner diameter of 143 millimeters (mm) (6 inch) but the pipes of 77 mm (3 inch) diameter was connected to the main loop for 3-inch valve tests (see Fig.2). The 3-inch swing check valve has a disc diameter of 82 mm, a disc full open angle of 61.3-degree, and the weight of the disc assembly in air of 1.3 kilogram (kg). The 6-inch valve has 134mm disc diameter, 62.7-degree disc full open angel, and 4.9 kg disc assembly weight.

Instrumentation

The water flow rate is controlled by the two downstream remote control valves (2-inch and 6-inch) indicated in Fig. 2. Flow measurement is made with both of the turbine flow meter and electromagnetic flow meter. The range of the turbine flow meter are 80~ 800 cubic meters per hour (m^3/hr) with an accuracy of ±1.0% full scale. On the other hand, the low flow rate, especially for 3-inch valve tests, were covered using the electromagnetic flow meter provided more accurate flow measurements with the range and accuracy of 5 ~ 180 m^3/hr and ±0.5% full scale, respectively. The average flow velocities are calculated from the flow measurements and the valve inlet diameter.

Pressure transmitter and pressure taps are located at the equivalent distance upstream and downstream of the test valves. The range of the pressure transmitter is 0~25 bar with 0.15% full scale. The differential pressure is also measured with a differential pressure transmitter. The potentiometer-type radial displacement transducer is used to measure the disc angular position. The backstop load is also obtained with load cell with the maximum measurable load of 200 kg to investigate the effect of the tapping on the disc stud integrity.

Test instrumentation feeds data directly to a high speed computerized digital data acquisition system which can display and process the data in real time. All the data collection and processing routines were written using the software developed for the tests.

Test Description

Flow loop tests on instrumented check valves were performed to validate the model prediction. During the test, the measured data include flow rate through the valve, valve disc position, differential pressure of the check valve, upstream and downstream pressures, and water temperature.

Steady state testing identifies characteristics specific to the valve design such as flow capacity, and the velocity required to fully open the check valve (V_{OPEN} & V_{MIN}). Additional experiments were performed to investigate the effects of the upstream disturbance source and distance from the check valve. The elbow and control valve (globe valve) are chosen as the disturbance source and the location of the disturbances are 2, 4, 6, 8, and 10 diameters upstream of the check valve.

Results and Discussion

Test Results

Figure 5 shows a set of three curves of the measured disc positions according to the average flow velocities for each of the 3-inch and 6-inch valves. Each curve is associated with three flow conditions such as uniform, elbow at 2 diameters upstream of the check valve, and globe valve at 2 diameters upstream of the check valve. The disc full open angles of these two valves are 61.3 and 62.7 degrees, respectively. From this figure, it seems that there is negligible effect of upstream flow conditions on the opening characteristics of the valve, because the curves are almost collapsed into one. However, Figs. 6 and 7, a plot to compare the disc fluctuations with the average flow velocity, show that the highest disc fluctuations are for elbow case. The effect of upstream flow condition can also be seen in the Figs. 8 and 9 which indicate the back stop load measured with the average flow velocity.

Figure 10 shows the maximum disc fluctuations with the elbow and globe valve at 2, 4, 6, 8, 10 diameters upstream of the 3-inch and 6-inch check valves. The measured V_{OPEN} and V_{MIN} for elbow case are presented in Fig. 11. The V_{MIN} velocity is determined as the minimum flow velocity at which the backstop load begins to increase after the disc is fully opened and the fluctuation level of disc is reduced below one degree. As one would expect, V_{MIN} is measured to be larger than V_{OPEN} but it seems that the effects of elbow and globe valve on both velocities become very small at distances of 4 diameters and beyond from the check valve.

Disc Pressure Drop Coefficient

Rahmeyer [2] proposed that the pressure drop coefficient be a function of the disc position in degrees as follows:

$$C_D = (K_b \cdot \theta)^{-3} \tag{8}$$

where combining the pressure differential and back seating forces, values of 0.025 and 0.035 are suggested as K_b for predicting V_{OPEN} and V_{MIN}, respectively. In this study, the disc pressure drop coefficient can be determined from the experimental data shown in Fig. 1 and Eq. (1) with $K_{SEAT} = 0$. The results are shown in Fig. 12, including the parametric calculations from Eq. (8) with $K_b = 0.12$, 0.04, 0.035, and 0.025. It can be seen that regardless of the upstream flow conditions, the best fitted values of K_b are 0.12 and 0.04 for 3-inch and 6-inch check valves, respectively. From this figure, K_b seems to be dependent on the valve size and further study on this would be desirable.

In Fig. 13, the model predictions with the best-fitted values of K_b are compared with the measured data for uniform flow condition, including V_{MIN}. The results show a good agreement between the predictions and the measured data.

Comparison with Rahmeyer's Model

The predictions of the disc position vs. the average flow velocity using the present model are compared with the experimental data and the predictions using Rahmeyer's model. The results for 3-inch and 6-inch check valves are shown in Figs. 14 and 15, respectively. From both figures, it can be seen that Rahmeyer's model with $K_b = 0.025$ does not predict the present valve position data well. However, his model predicts the valve positions with better agreement for the use of $K_b = 0.12$ and 0.04 for 3-inch and 6-inch check valves, respectively.

Concluding Remarks

The existing minimum velocity model for a swing check valve, Rahmeyer's model, is modified by considering four different forces acting on the disc such as back seating force, disc assembly weight, flow inertia and pressure differential forces. In this study, the back seating force and pressure differential force are separately treated. From the comparisons of the model predictions with the experimental data show that the present model predicts the experimental results well but Rahmeyer's model with his K_b of 0.025 does not predict the present data well. However, his model predictions with K_b = 0.12 and 0.04 for 3-inch and 6-inch check valves, respectively, show better agreement.

The upstream flow disturbances due to elbow and globe valve at 2 ~ 10 diameters upstream of the check valve produced minor effects on the check valve performance compared to the uniform flow condition.

Acknowledgement

This study has been carried out under the Nuclear R & D Program funded by the Ministry of Science and Technology (MOST) in Korea.

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Table 1 Minimum Flow Velocity Models for Swing Check Valves

	Model	
Chiu & Kalsi [1]	$V_{MIN} = \sqrt{\dfrac{g \cdot B \cdot W_{EFF} \cdot \sin\theta}{2 \cdot \rho \cdot A_D \cdot \cos^2\theta}}$	- B = buoyancy correction factor (0.9 for water) - W_{EFF} = effective disc assembly weight.
Rahmeyer [2]	$V_{MIN} = \sqrt{\dfrac{M_{WT}/\rho}{K_{VEL} + K_{\Delta P}}}$ where $M_{WT} = B \cdot W_{EFF} \cdot \sin(\theta + \beta) \cdot L$; $K_{VEL} = A_{EFF} \cdot (h + 0.5 \cdot z) \cdot \cos\theta$; $A_{EFF} = \sqrt{2 \cdot D_d \cdot z^3 \cdot \cos^3\theta - z^4 \cdot \cos^4\theta}$; $K_{\Delta P} = A_D \cdot L \cdot (K_b \cdot \theta)^{-3}$	

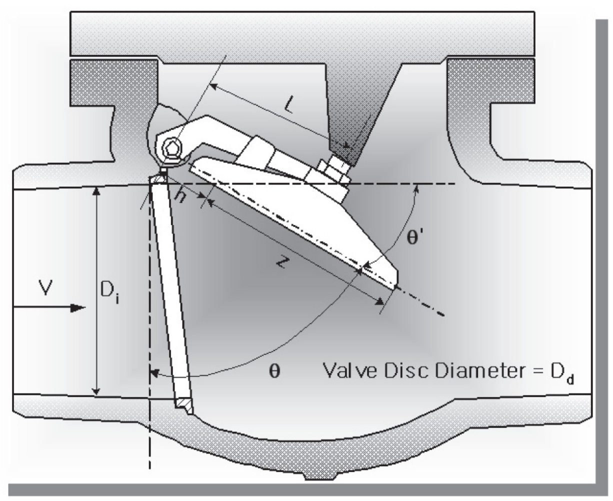

Fig. 1 Typical Swing Check Valve for Minimum Flow Velocity Model

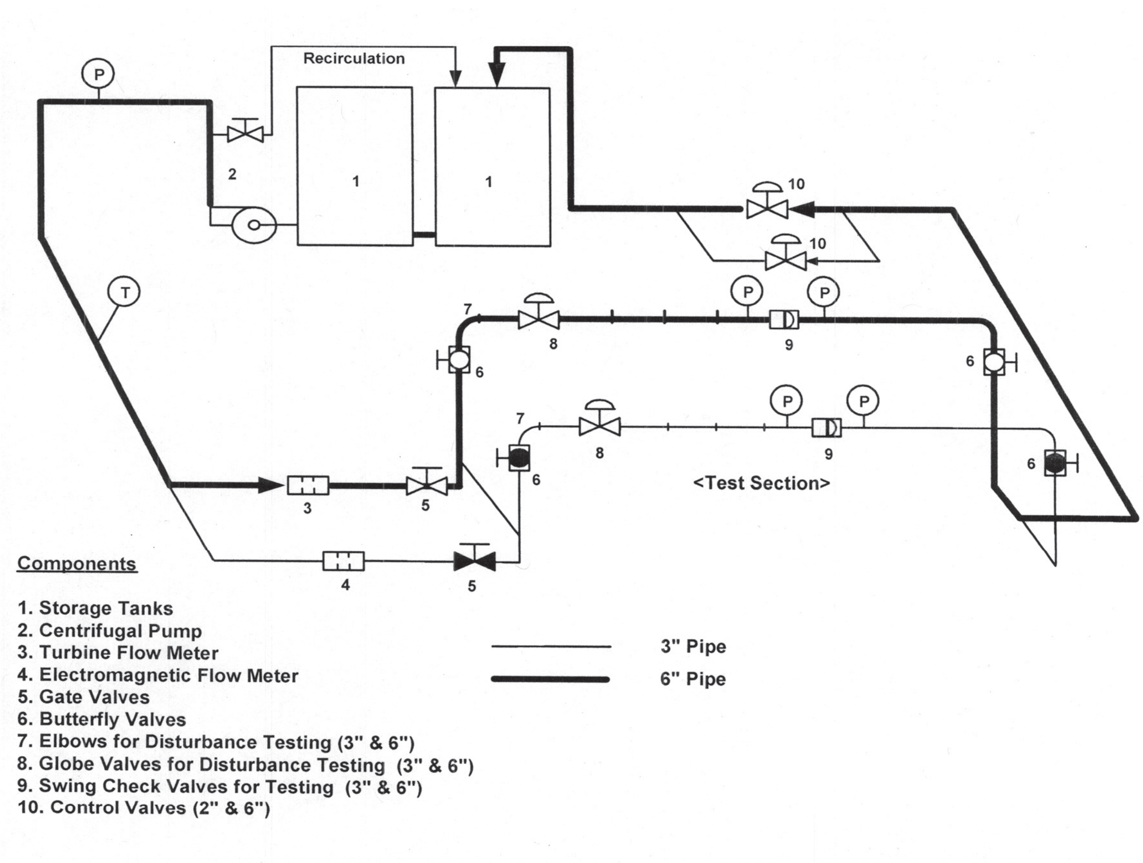

Fig. 2 Schematic Diagram of Experimental Loop for Swing Check Valve Performance Tests

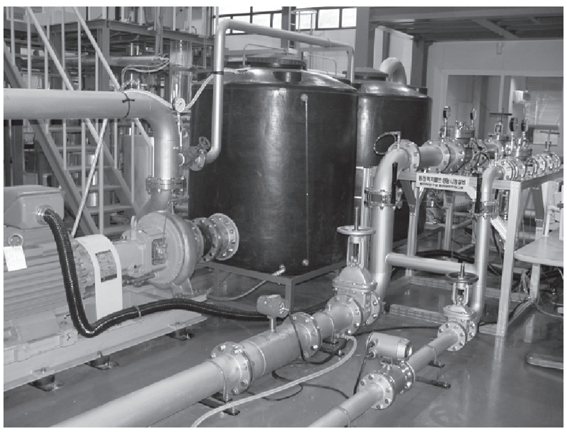

Fig. 3 Picture of Experimental Loop

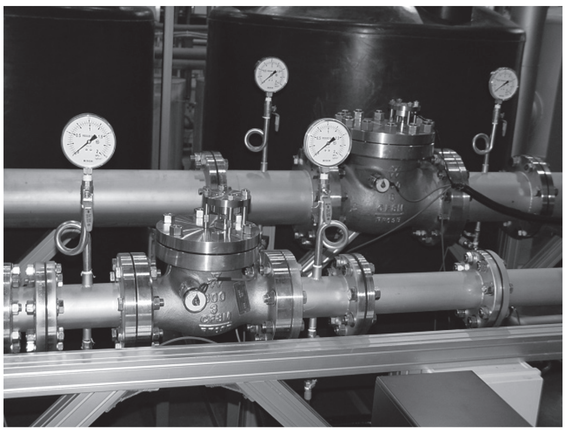

Fig. 4 3-inch and 6-inch Swing Check Valves for Tests

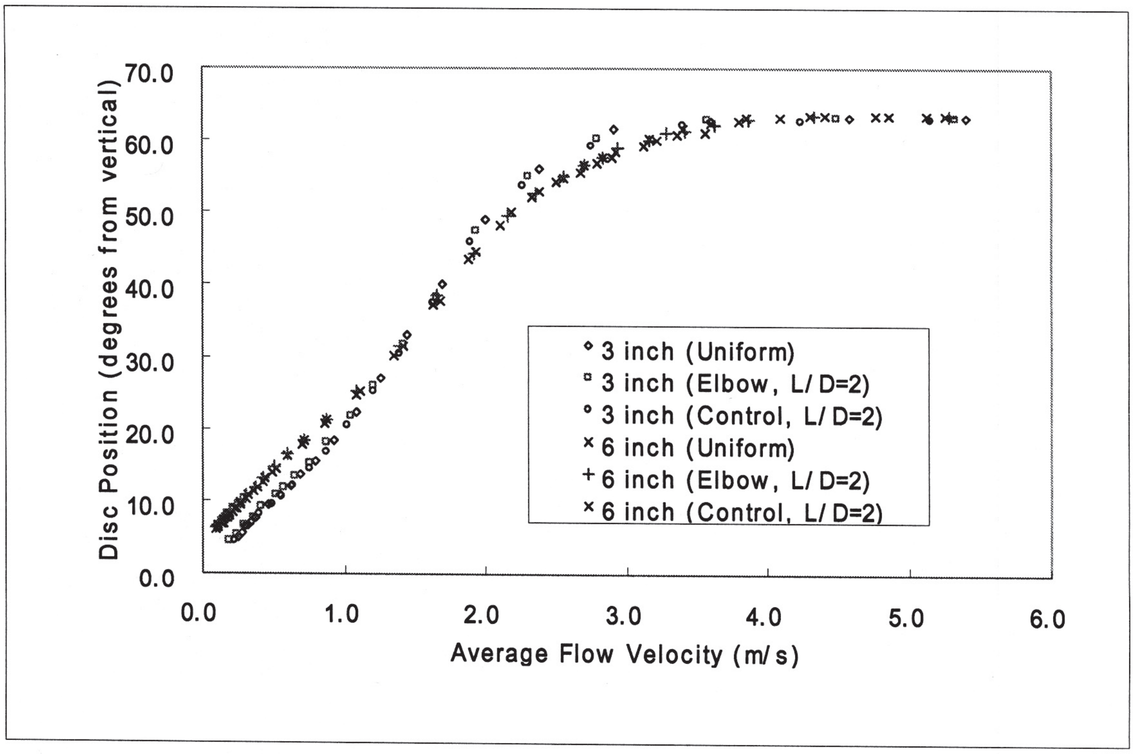

Fig. 5 Measured Disc Position with Average Flow Velocity through the Valve

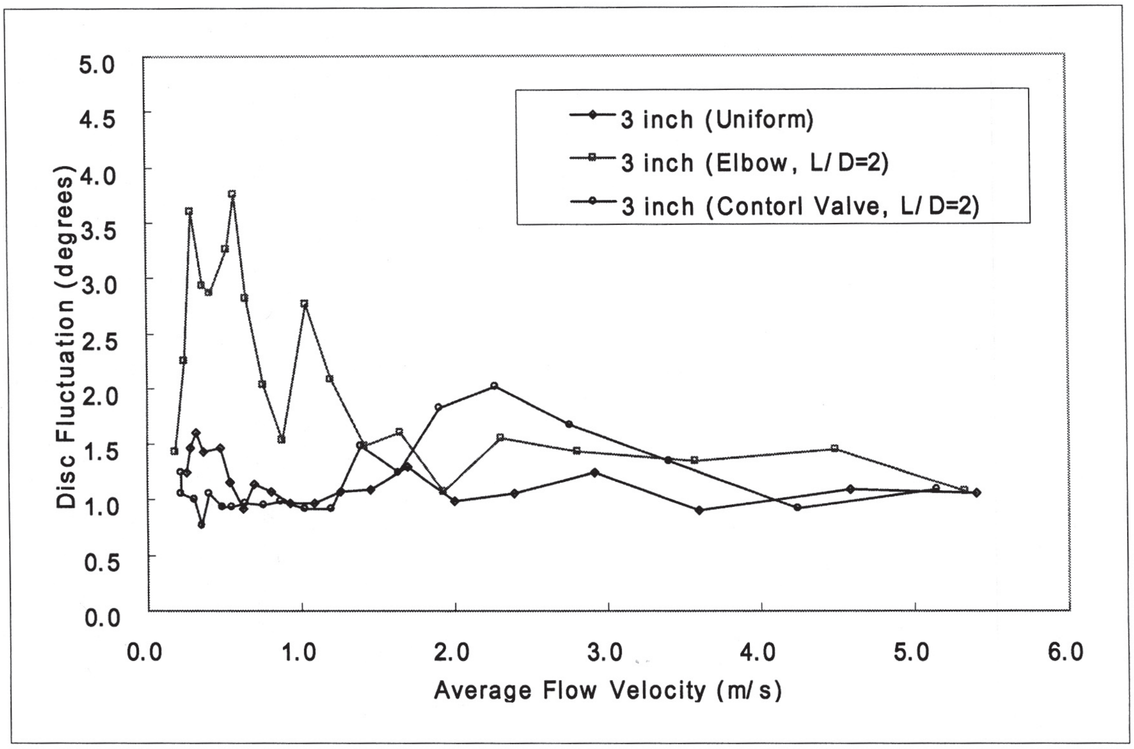

Fig. 6 Typical Disc Fluctuation vs. Average Flow Velocity for 3-inch Swing Check Valve

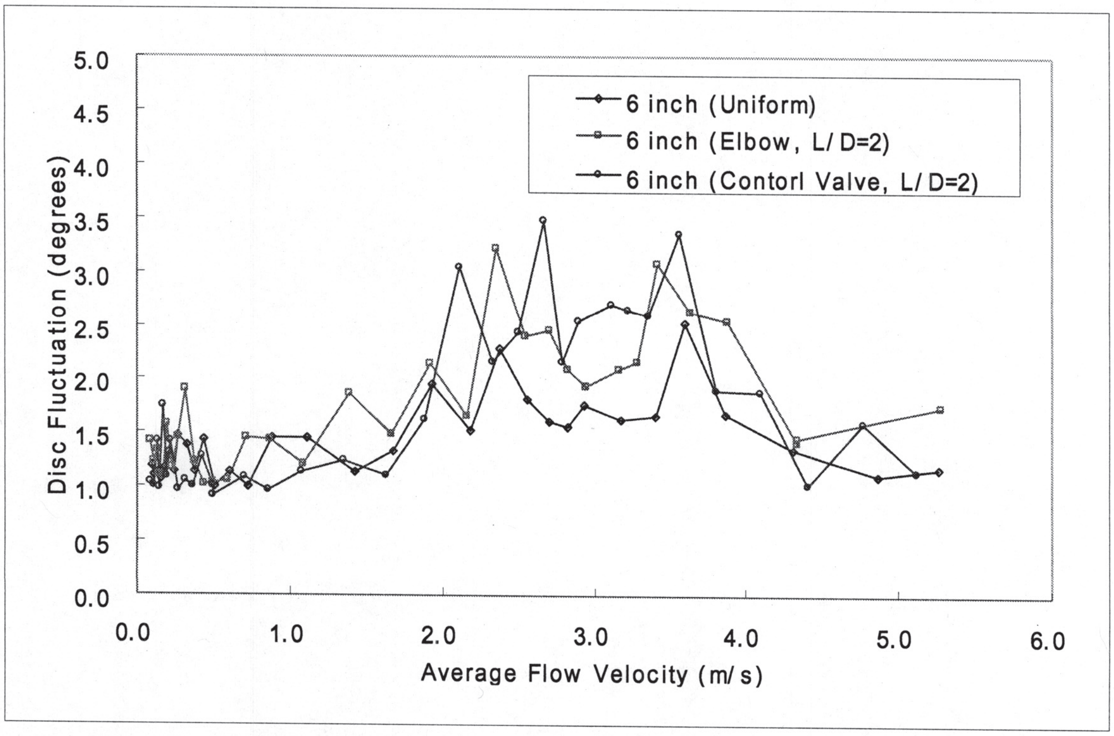

Fig. 7 Typical Disc Fluctuation vs. Average Flow Velocity for 6-inch Swing Check Valve

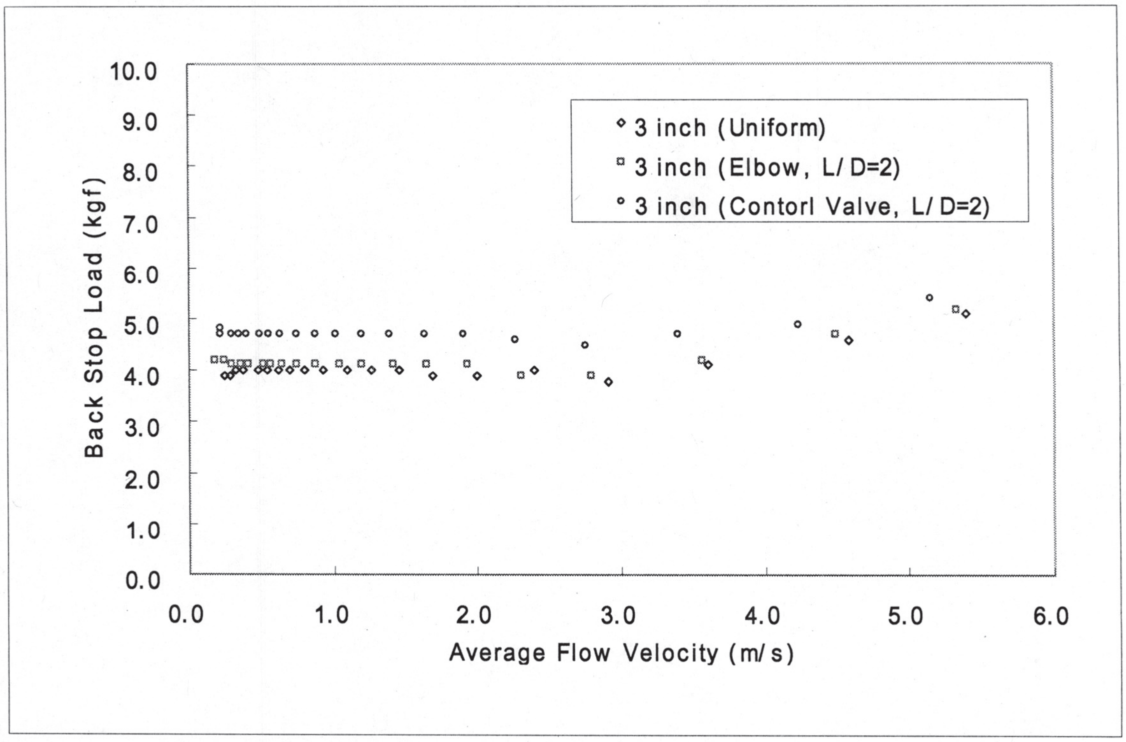

Fig. 8 Back Stop Load for 3-inch Swing Check Valve

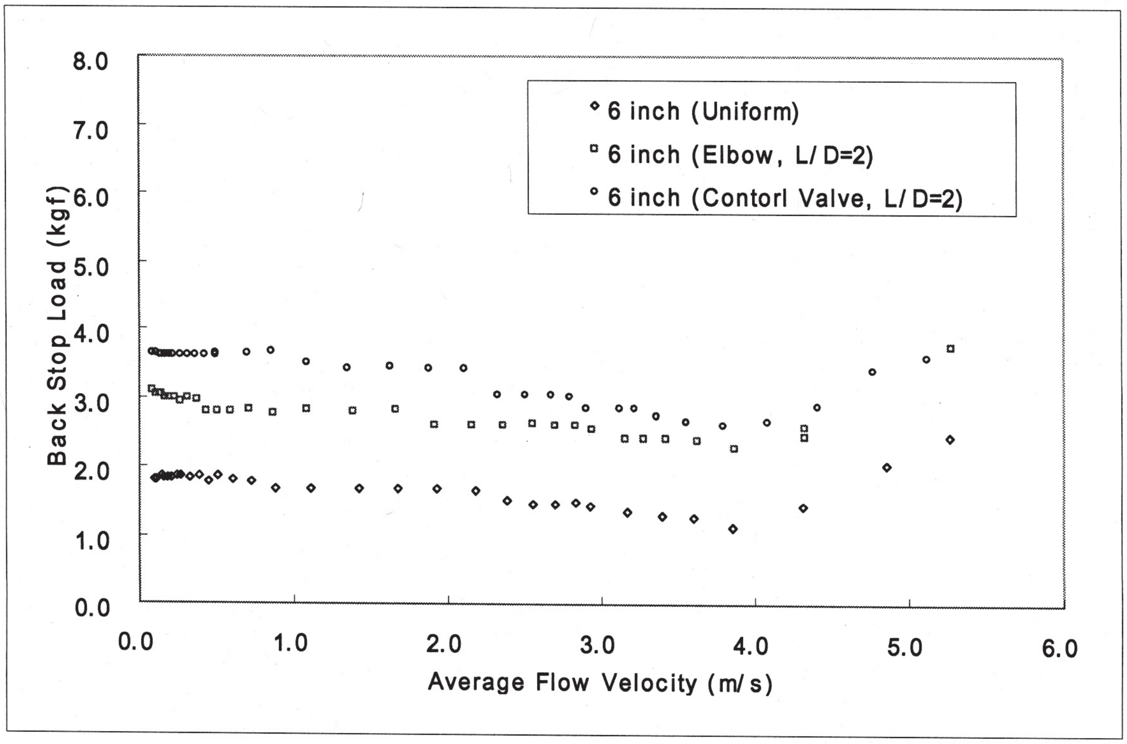

Fig. 9 Back Stop Load for 6-inch Swing Check Valve

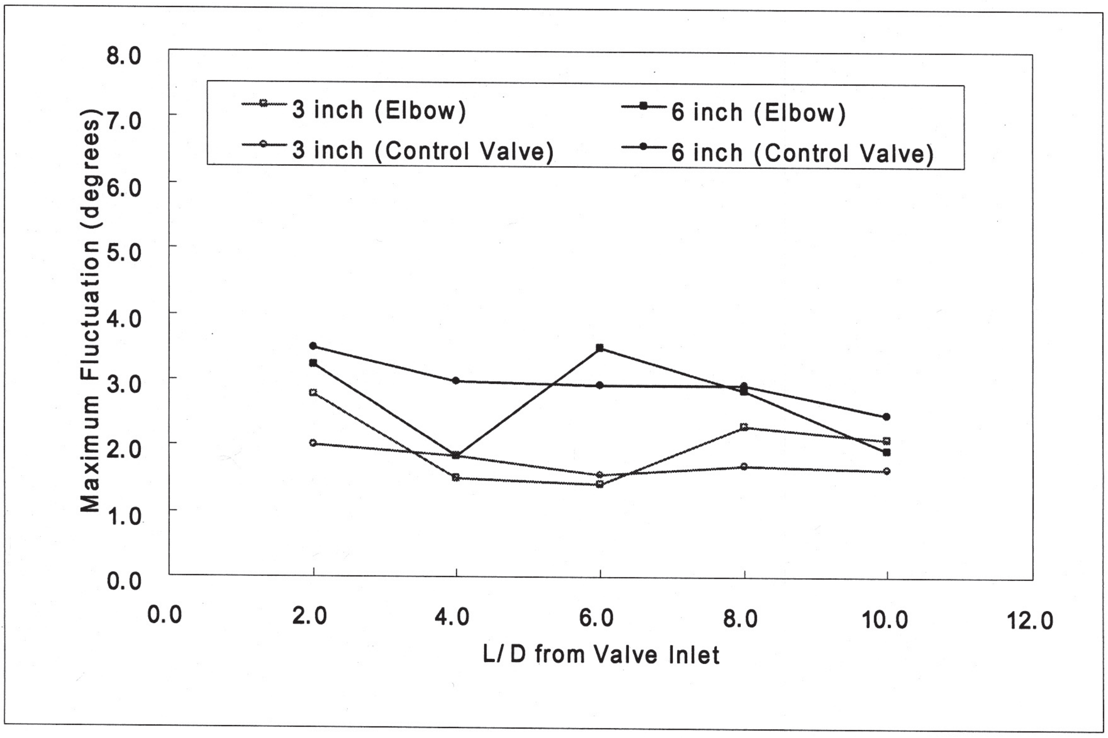

Fig. 10 Maximum Fluctuation with Disturbance Source and Distance from Check Valve

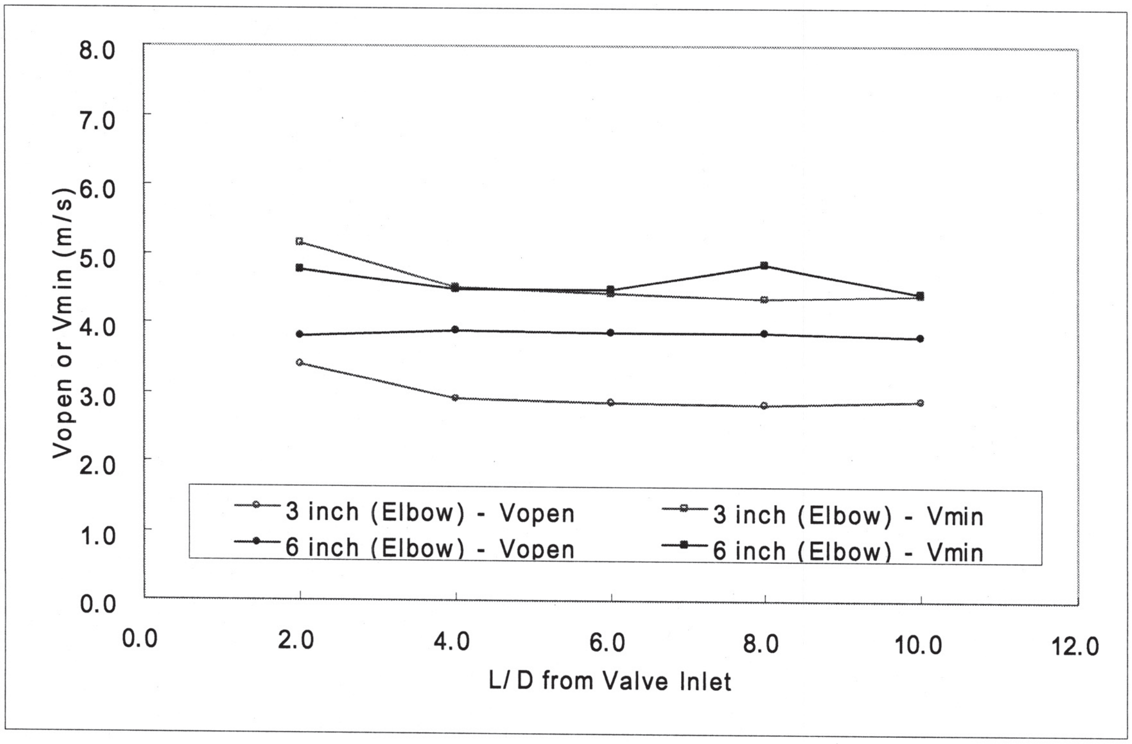

Fig. 11 ***V_{OPEN}* and *V_{MIN}* with Disturbance Source and Distance from Check Valve**

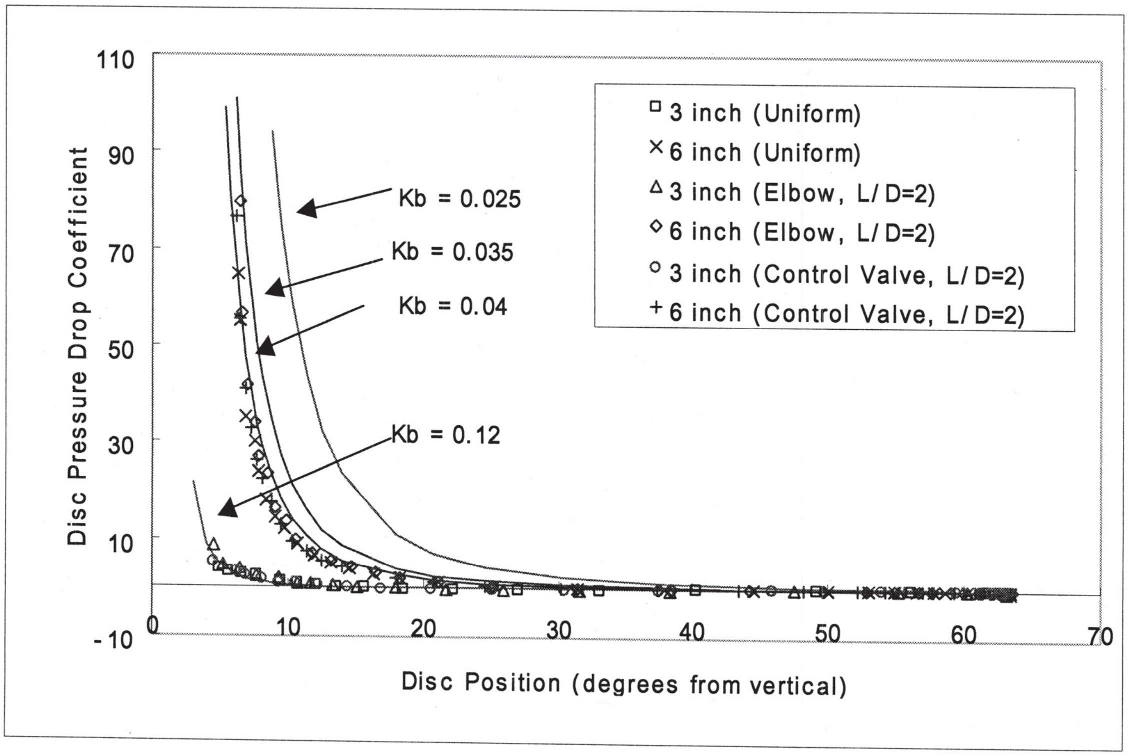

Fig. 12 Measurements of Pressure Drop Coefficient C_D

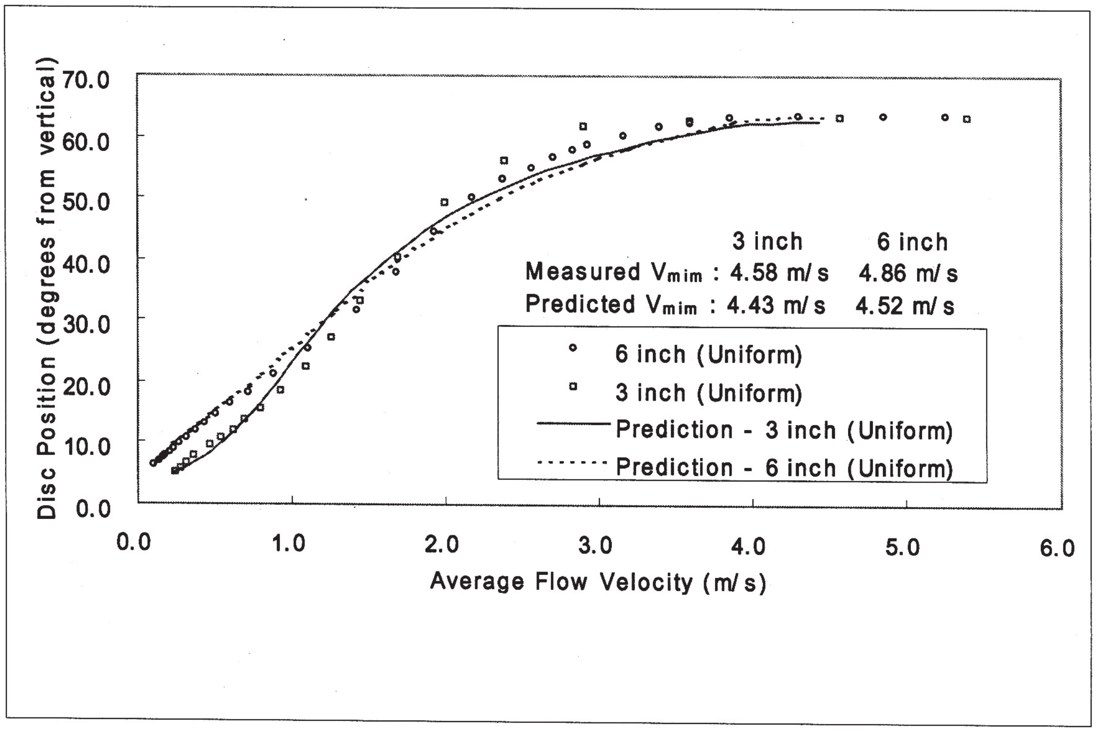

Fig. 13 ***Comparison of Model Prediction with Experimental Data***

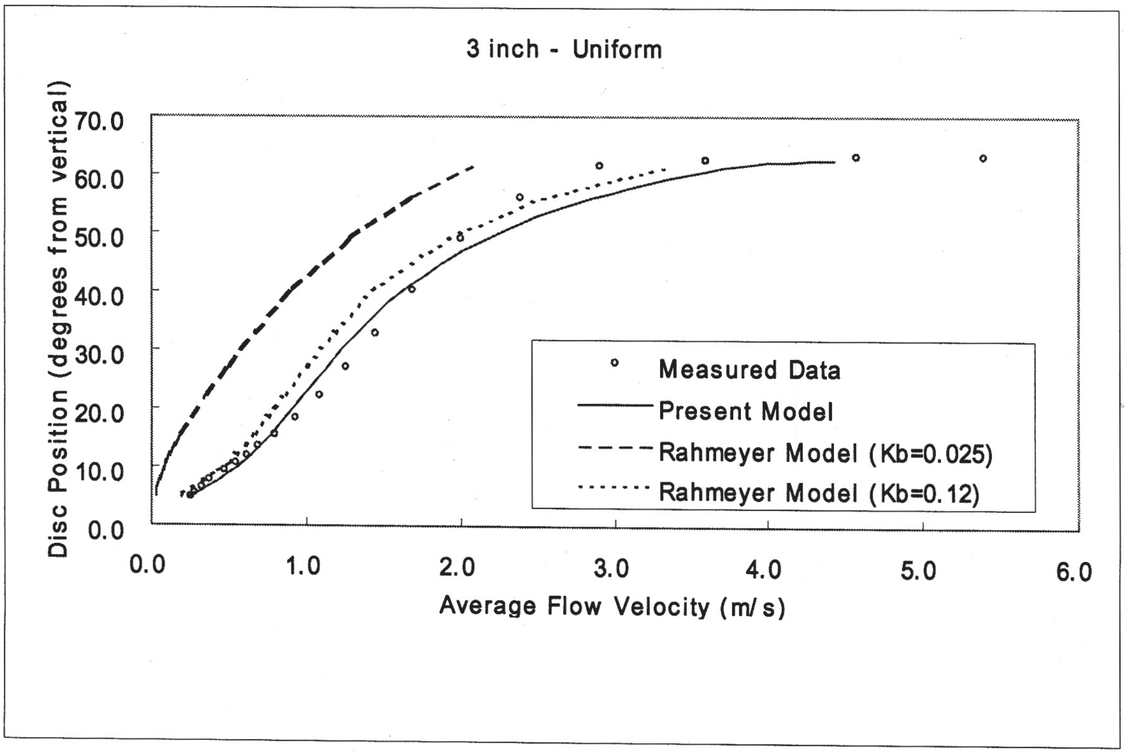

Fig. 14 Comparisons of Present and Rahmeyer's Models with Experimental Data for 3-inch Swing Check Valve

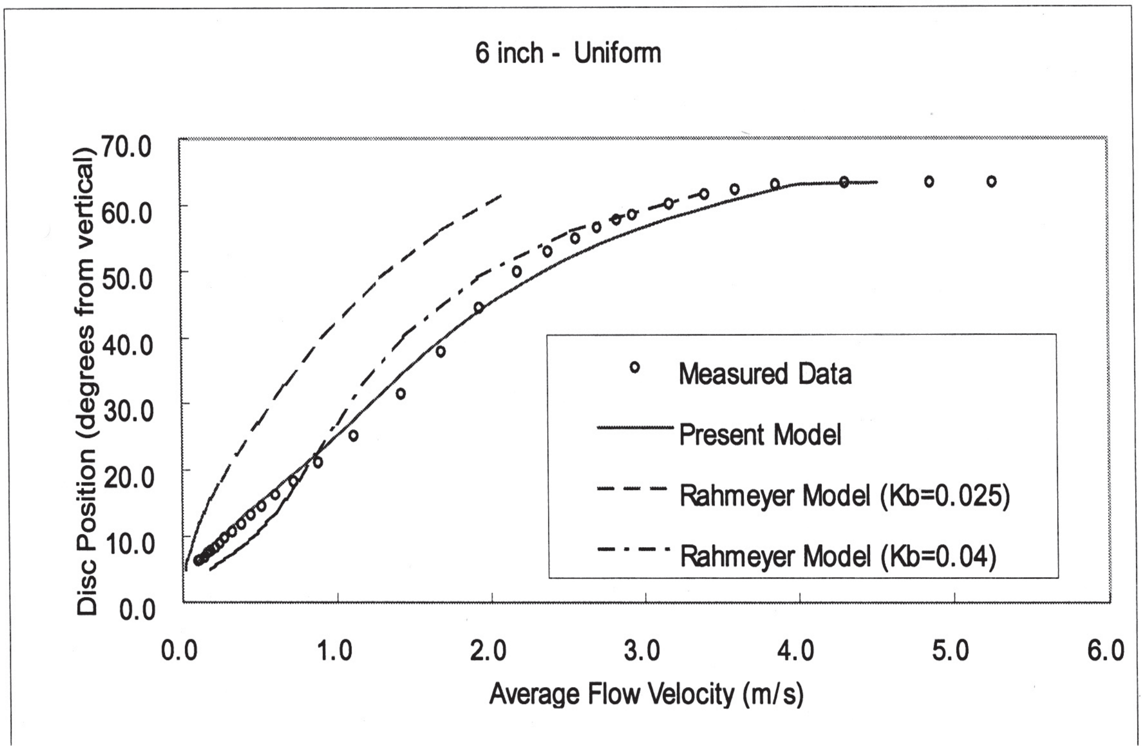

Fig. 15 Comparisons of Present and Rahmeyer's Models with Experimental Data for 3-inch Swing Check Valve

Instrument Air Application Review – Enertech NozzleCheck Design Eliminates Maintenance Rule and Appendix J Test Failures

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Abstract

Rochester Gas and Electric's Ginna Station initiated a project to eliminate chronic Local Leak Rate Test (LLRT) and Maintenance Rule failures of a small bore check valve in the Instrument Air System using advanced valve design technology. Starting with the root cause analysis of the problem, this paper outlines all aspects of this project: the evaluation of various replacement candidates, an economic cost justification and the design change process. It concludes with a performance evaluation of the replacement valve after 18 months of operation.

INTRODUCTION

The Instrument Air system at Ginna, a 490 MWE, Westinghouse design Pressurized Water Plant, is used to supply air to various components both inside and outside the Containment building. Air is supplied to Containment via two Containment isolation valves, one AOV located outside and one check valve located inside, **See Figure 1**. To ensure that fission products are contained within the Containment during a Loss of Coolant Accident (LOCA), all piping penetrations have Containment boundary valves that are required to seat tightly against a postulated accident pressure of 60 psig (pounds per square inch gage). In accordance with the test frequency established per Appendix J, OPTION B, these isolation valves undergo an LLRT that is conducted to verify the capability of the valve to contain the release of radioactive fission products.

The performance requirements for Containment boundary check valves exceed the ability of many valve designs. Since most check valves were designed to support high-pressure seat leakage tests, many will not pass the stringent requirements of site-specific LLRT's even in the as-new condition. When the adverse effects of corrosion, disc oscillation, debris and numerous open-closed cycles are factored in, it is even more unlikely that a check valve will maintain tight shutoff following numerous operating cycles.

To improve performance and resolve obsolescence issues, Ginna Station replaced the original swing check with a poppet style check valve design that utilized a soft seat and spring assisted closure to overcome the obstacles caused by the low differential pressure LLRT. This design also failed to meet the expectations of long-term LLRT success without requiring refurbishment each outage. An alternate design was selected for replacement that utilized a unique pressure-velocity profile along the disk that eliminated wear related degradation by providing the necessary force to fully open the valve. This design has been inspected and tested after one eighteen month cycle with no indication of wear or degradation of seat tightness. Although the implementation of a Design Modification of an ASME Section III component is costly, this proved to be a cost justified endeavor that not only reduced operating expenses but improved plant safety.

APPLICATION DESCRIPTION

Tag #:5393

Operating Pressure:	115 psig
Operating Temperature:	300° F
Normal Operating Flow:	5 scfm (standard cubic feet per minute)estimated to occur 90% of the time.
Velocity @ 75 scfm:	53.63 ft/sec (feet per second)
Upstream piping configuration:	straight
Valve Orientation:	vertical flow up, **Figure 2**

Testing Requirements: An LLRT is performed using a Leak Rate Monitor (LRM) Thermal Mass Flow Measurement Device connected to the downstream vent connection with the upstream section vented to atmosphere. The test is conducted as follows:

1. Isolate test volume
2. Pressurize downstream side to 60 psig using the integral regulator in the LRM

3. Record the makeup air flow rate required to maintain 60 psig once indicated leak rate is stable

A successful LLRT is one where the leak rate is less than the Administrative value, in the case of V-5393, less than 2480.0 sccm (standard cubic centimeter per minute).

In addition to the LLRT, Ginna's IST (In Service Testing) program requires a full-open and prompt closure valve exercise verification at a refueling interval frequency.

SUMMARY OF PROBLEMS

The originally installed swing check valve was replaced in 1993 due to obsolescence and poor LLRT performance. A soft seated, poppet check valve was selected to replace the swing check based on the advantages of its spring loaded, soft seated design. Although the poppet check valves passed the LLRT during factory acceptance testing, the valves could not pass the site LLRT after one cycle of operation. The poppet check valve was removed from the system, disassembled and inspected. Excessive wear along the stem and stem guide was noticed during the inspection. This wear was indicative of disc oscillation over an extended period. It didn't appear that the valve ever fully opened. This wear increased friction during the closing stroke and imposed angular and transverse misalignment preventing the valve from achieving proper seat-to-disc engagement. This wear also resulted in a longer closure time during the prompt closure test. Refurbishment of the valve required new o-rings, seat, stem and in some cases, a new body. Parts were kept in stock to support maintenance without impacting outage schedules or equipment availability. A summary of the cost of maintenance activities:

Maintenance to support rebuild of the valve:

25 hours x $65/hr = $1625

Post Maintenance Testing and data entry:

15 hours x $65/hr = $975

Analysis by Systems and Performance Engineering:

10 hours x $65/hr = $650

Replacement Parts: = $4000

Total Refurbishment Cost per Outage $7250

In addition to maintenance costs, the following issues contributed to the cost justification:

- Inability to extend LLRT testing per Appendix J, Option B
- Non-compliance with Maintenance Rule
- Appendix J Program Repeat Failures
- Negative impact on Probabilistic Safety Assessment

THE MODIFICATION PROCESS-REVIEW OF SELECTED REPLACEMENT VALVES

The primary cause of the chronic failure of the poppet check valve was attributed to misalignment of seating surfaces due to wear along the shaft. The goal of the replacement valve selection process was to find a valve which would supply system loads while essentially maintaining a full-open position, thereby minimizing the wear of critical surfaces under normal service conditions.

The force acting on the disc at a velocity of 54 ft/sec of air with a density of 0.585 lbm/ft3 (pounds mass per cubic feet) is equivalent to the force exerted by ambient water velocity of approximately 5 ft/sec. To simplify the discussion related to Vmin, we will refer to velocities based on ambient water. Ginna wanted a check valve with a Vmin less than 5 ft/sec(water) to eliminate the wear caused by disc oscillation. Experience with swing check and piston check designs indicated the following Vmin assuming straight upstream piping with no proximity to turbulence:

Vmin of Swing Check: 10-20 ft/sec water

Vmin of lift check: 20 ft/sec water

Vmin of poppet check: 10 ft/sec water

Since swing and lift checks could not meet the design objectives of operating in the full open position, and the poppet check exhibited accelerated wear, an alternate check valve design was evaluated. Ginna had installed 14" Model DRV-B and 8" Model DRV-Z NozzleCheck valves in the Service Water and CCW pump discharge applications, respectively, in 1994 to eliminate problems primarily related to water hammer. These valve designs had shown no indications of wear induced by low velocity operation after many years of operation in contrast to the hinge pin wear observed with the originally installed swing checks.

Ginna requested a preliminary application review from Enertech and they recommended a Model ERV-Z valve design based on its ability to operate in the fully open position at relatively low velocity without sacrificing flow coefficient. The NozzleCheck product line, comprised of four basic models, had been utilized in over 800 critical Nuclear Plant applications around in the world to replace conventional check valves in challenging applications. This experience provided a good experience base but none of the applications were identical to the service and testing conditions of Ginna. A rigorous design review was conducted to ensure that the ERV-Z would provide the desired performance characteristics. This review compared the ERV-Z, Figure 3, with the installed poppet check, Figure 4, and isolated the similarities and differences that would be the basis for the final valve selection.

Design Review Summary

Body Design

The Poppet Check and NozzleCheck are both Axial Flow Check valves. Ginna's Poppet check valve had a three-piece body consisting of screwed-end, end pieces with a wafer body sandwiched between them sealed with an O-ring on the downstream and with the seat on the upstream side. The ERV-Z NozzleCheck body is manufactured as a one piece casting, bar or forging. The Poppet Check valve body has no change in internal diameter (ID) along the length of the center section; its shape is symmetric similar to a pipe. The NozzleCheck body is contoured with a gradually decreasing ID, which reaches a minimum on the inlet side of the disc and is gradually increased along the length of the valve. There are no joints that must seal tightly on the NozzleCheck body design eliminating the risk of body leakage.

The Poppet Check integrates the disc guide into the body as one piece. The NozzleCheck design utilizes a separate diffuser that is retained in the body using a retaining ring that is captured in a slot machined on the body ID near the outlet of the valve. Having a separate diffuser was viewed as an advantage since it could be easily replaced if the sliding surfaces were damaged instead of replacing the center section of the body.

Disc Guiding

The disc and shaft are one-piece in both designs. The weight of the disc/shaft is supported by a bearing surface within the body of the Poppet Check and within a diffuser in the NozzleCheck. This bearing surface is downstream of the seat on both designs offering protection from direct impingement of the fluid minimizing contamination of the sliding surface with media borne debris and corrosion products. The percent of shaft length engaged in the guide was higher for both the fully open and closed disc positions in the ERV-Z design. Maximizing shaft engagement offers an advantage in horizontal applications but was not considered a factor in this vertical application where there is no radial loading.

Seat Design

The poppet check design used a Viton seat captured in the body that acts as both a seat and also a body seal. There is a wide area contact between the disc and seat. As the nuts are tightened on the studs, compressing both the upstream seat/seal and the downstream O-ring seal, the seat moves in response to the compression. This may have been a factor in the inability of the poppet valve to pass the LLRT since it creates the potential for misalignment between seat and disc.

The NozzleCheck soft seal is retained within the disc, Figure 5. The Viton O-ring is the primary seal with a metal-to-metal backup seal if the O-ring were to be removed. The O-ring provides a relatively narrow contact band compared to the poppet check valve and is not affected by any compression of the body. This was viewed as a contributing factor affecting seat leakage performance.

Geometry of Flow Path

The difference between the two check valve types is most apparent in the comparison of flow patterns. The flow through the NozzleCheck is similar to that through a convergent-divergent nozzle, a gradually decreasing and then gradually increasing area creating a low-pressure zone immediately downstream of the disc. This low-pressure area generates a force on the disc in the open direction. The low pressure is gradually recovered as the area expands towards the outlet of the valve. The shape of the diffuser, coupled with the body contour, provides a smooth, symmetric flow path with no projected disturbances to cause vortices or turbulence. The poppet check disc protrudes into the flow path with no diffuser on the downstream side. This allows pressure to equalize on both sides of the disc once the poppet partially opens. This equalization of pressure prevents the disc from achieving a fully open position and causes the disc to oscillate degrading the surfaces of the shaft and bearing surfaces.

To model the effect of different valve geometries, Enertech built a test loop similar to the configuration of the Ginna application with the check valves in a vertical, flow up orientation. This loop was used to circulate water through specially designed NozzleChecks with see-through bodies. The test was conducted with two different diffuser designs. Valve 1 had a 2" diffuser with the outside diameter decreased eliminating the nozzle shape resulting in a larger flow area. Valve 2 had a standard ERV-Z NozzleCheck geometry with a 1.5" diffuser. Figure 6 compares the Cv (flow coefficient) and Figure 7 compares the difference in percent open. This test illustrates the dramatic effect of the geometry of check valve internals. Without a specific convergent-divergent nozzle geometry, there is no low-pressure area created which is necessary to provide the force required to hold the disc fully open without oscillation.

When velocity was increased to greater than 13 ft/sec (135 gallons per minute) , the modified NozzleCheck didn't open past 30%. When the standard diffuser was used, with the same spring, the valve fully opened at the calculated velocity of approximately 4 ft/sec (40 gallons per minute). Even with smaller internals, the valve achieved the full open position and attained a much higher Cv compared to the larger diffuser with the standard contour machined away. This allows a stronger spring to be used, providing seat load and alignment, and still achieve full open operation compared to valves without this specific nozzle geometry.

Final Selection of a Replacement Valve

The decision was made to purchase two, 2” ANSI 300, ASME Section III, Class 2, ERV-Z NozzleChecks. The final NozzleCheck configuration was designed to minimize the extent of the modification by maintaining the following characteristics similar or identical to the poppet check valve:

- Body material
- Disc material
- Seat material
- End connections
- Weight
- Face-to-face dimension

The factory acceptance testing was performed by vendor and Ginna Engineering personnel and consisted of a “prompt closure” test and a 60 psid (pounds per square inch differential) LLRT. Ginna constructed an exact replica of the associated plant piping configuration which was shipped to Enertech’s facility and used during the prompt closure tests.

The acceptance LLRT results were: ERV-1, 0.1 sccm and ERV-2, 0.3 sccm .

The valve demonstrated instantaneous closure during the prompt closure test and maintained the 60 psig downstream pressure after the upstream volume was rapidly vented.

The standard ERV-Z design has been upgraded over the last few years by providing sliding surfaces of a differential hardness and of extremely wear resistant materials to allow operation in high cycle applications without wear or galling. In this application, since full-open operation was expected during normal operation, the 316SS (Stainless Steel)-on-316SS sliding surface configuration was maintained with little expected risk of galling.

IMPACT ON SYSTEM HEALTH

The installation of the ERV-Z, Figure 8, was a relatively easy evolution since the size, end-connections and weight of the valve were maintained. The estimated payback was estimated to be two cycles when all factors were evaluated. After 18 months of operation, the NozzleCheck was tested at 60 psid per the LLRT procedure with zero leakage. It also passed the Refueling interval valve exercise/prompt closure IST test with essentially an instant closure and no detectable delay or lag when traveling to the closed position.

Upon consecutive rounds of ASME Code and Appendix J LLRT testing during RFO’s (refueling outages) 2003 and 2005, the test interval for the LLRT could be extended out to 60 months in accordance with OPTION B. In addition, all associated repetitive maintenance tasks could likewise be extended. The Maintenance Rule compliance issue will be resolved which has a valuable regulatory, albeit intangible, price benefit. The Appendix J program would be rid of a consistent poor performer, which would positively impact the status of the overall program. The valve availability is not really impacted since the poppet check valve always remained operable and in service even at its peak as a poor leakage performer. There is no significant ALARA benefit since the valve is in a non-contaminated system and is located in a low-dose rate area, typically 1 mrem (millirem) or less.

CONCLUSION

Many of the testing, inspection and performance requirements imposed on check valves in safety related, nuclear plant applications exceed the capabilities of many traditional check valve designs. Normal flow rates are many times much less than worst-case accident/design flow rates causing check valve discs to oscillate causing wear to sliding and rotating surfaces. Even the highest quality check valve designs may moderate wear that is sufficient to create misalignment of the seat/disc interface preventing the valve from passing under low pressure seat leakage tests. In these applications, valves that fully open at very low velocity, are necessary to provide a long term, maintenance free operation without leakage.

The proprietary design of the NozzleCheck valve was developed in 1935, primarily to eliminate water hammer damage, and has been installed in nuclear plants since 1972. The low-pressure area created by the conversion of pressure to velocity provides a valuable opening force on the disc allowing the valve to function in the fully open position when other check valve designs operate partially open. The full open, non-oscillating operation, in combination with a strong spring force, provides a tight shutoff at both low and high-pressure after many cycles of continued operation. In many applications, the NozzleCheck is an economical alternative to repetitive corrective and preventative maintenance that also increases safety and reliability.

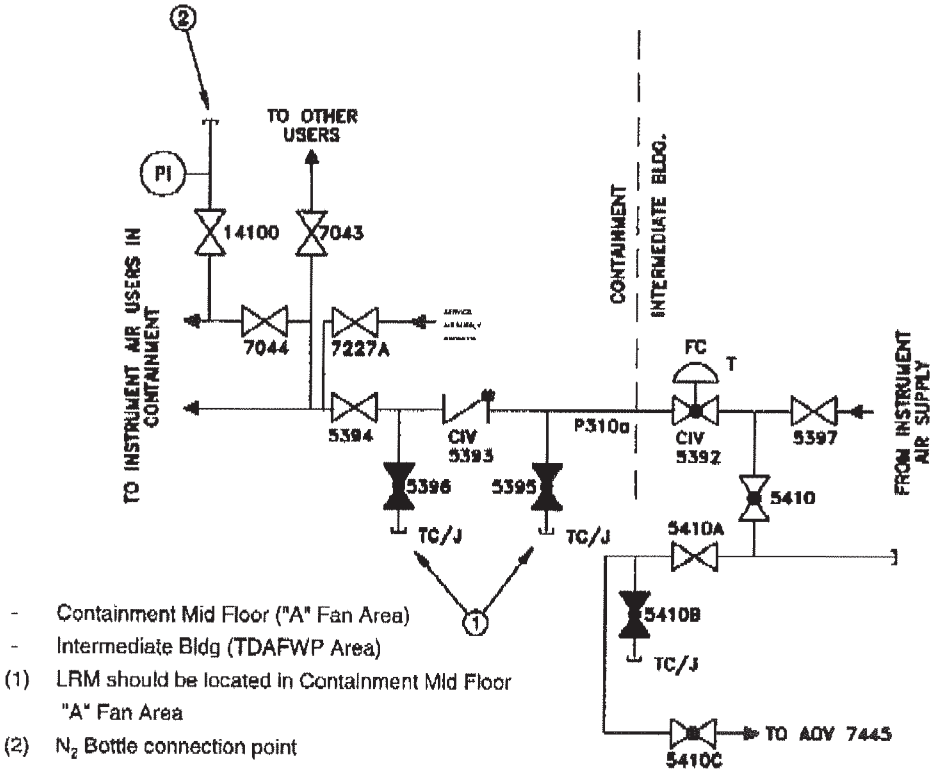


Figure 1 – System Schematic

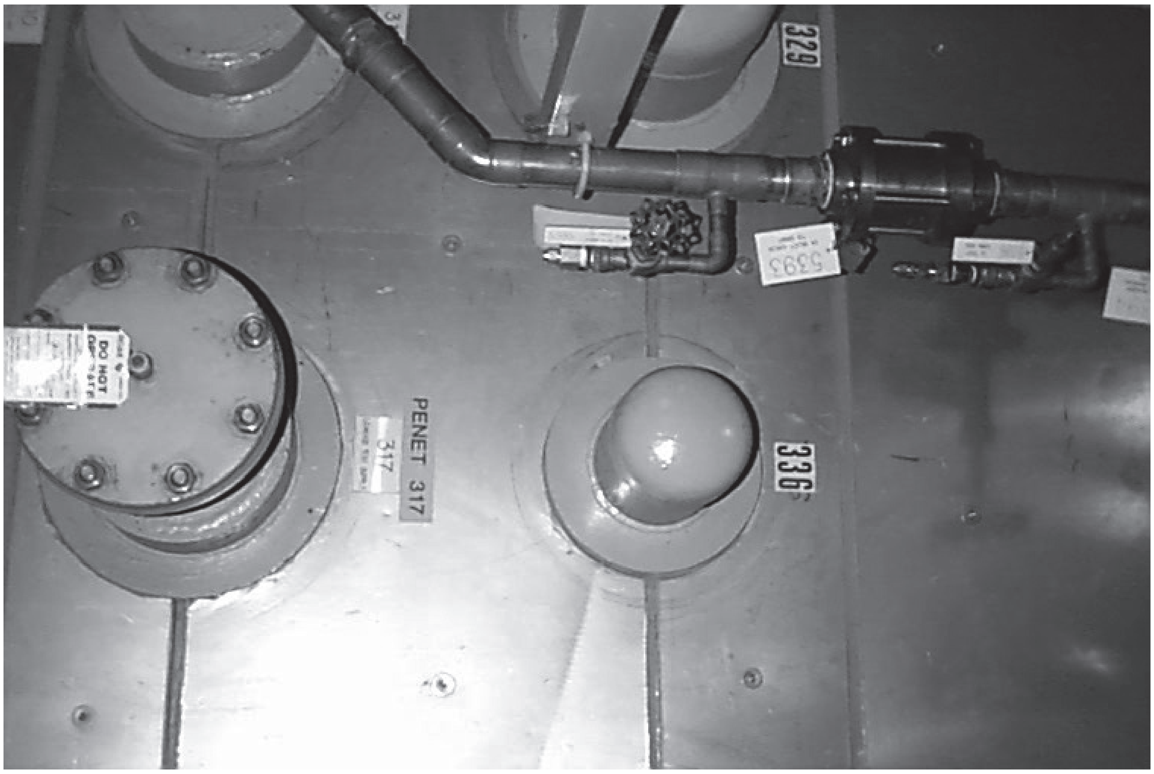
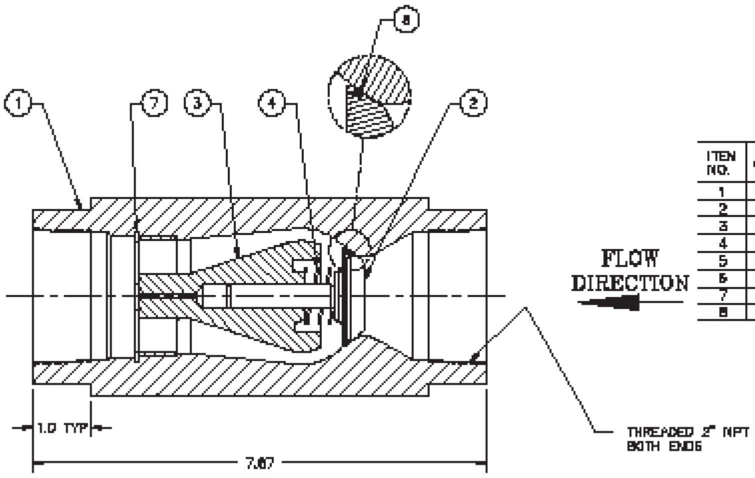


Figure 2 – Picture of Poppet Check Valve Installation



ITEM NO.	QTY	DESCRIPTION	MATERIAL SPEC.
1	1	VALVE BODY	SA 479 TP316
2	1	DISC	SA 479 TP316
3	1	DIFFUSER	300 SERIES ST. STEEL
4	1	SPRING	17-7 PH ST. STEEL
5	1	NAMEPLATE	STAINLESS STEEL
6	2	DRIVE SCREW	STAINLESS STEEL
7	1	RING, RETAINING	STAINLESS STEEL
8	1	SEAL, O-RING	VITON

Figure 3 – ERV-Z drawing

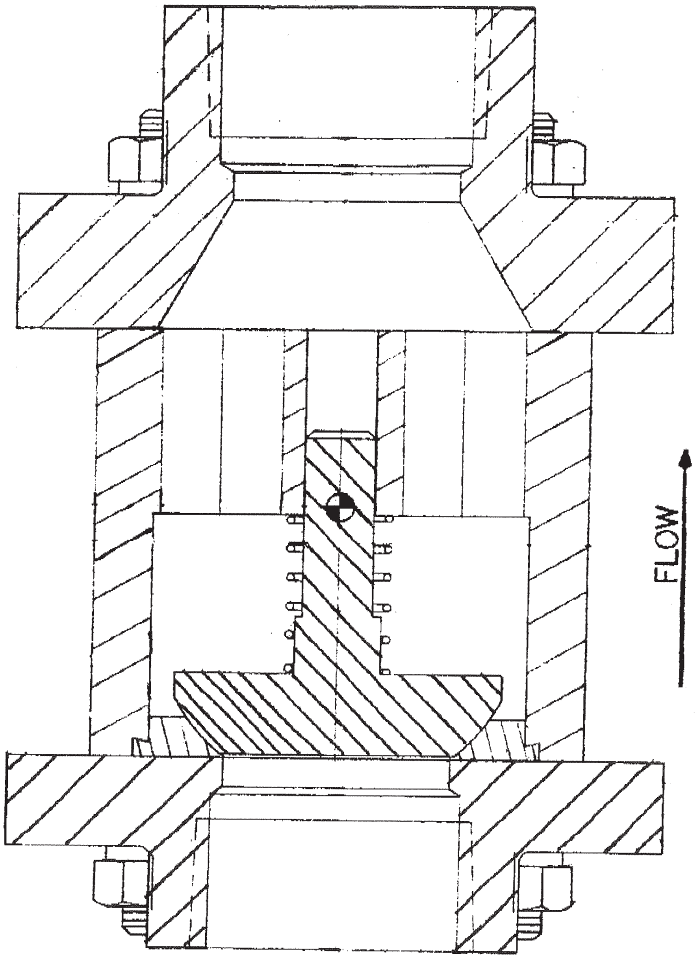


Figure 4 – Poppet Check Valve Drawing

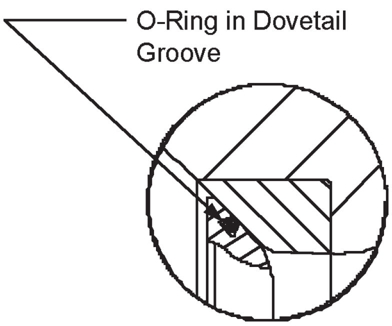


Figure 5 – ERV-Z Soft Seat detail

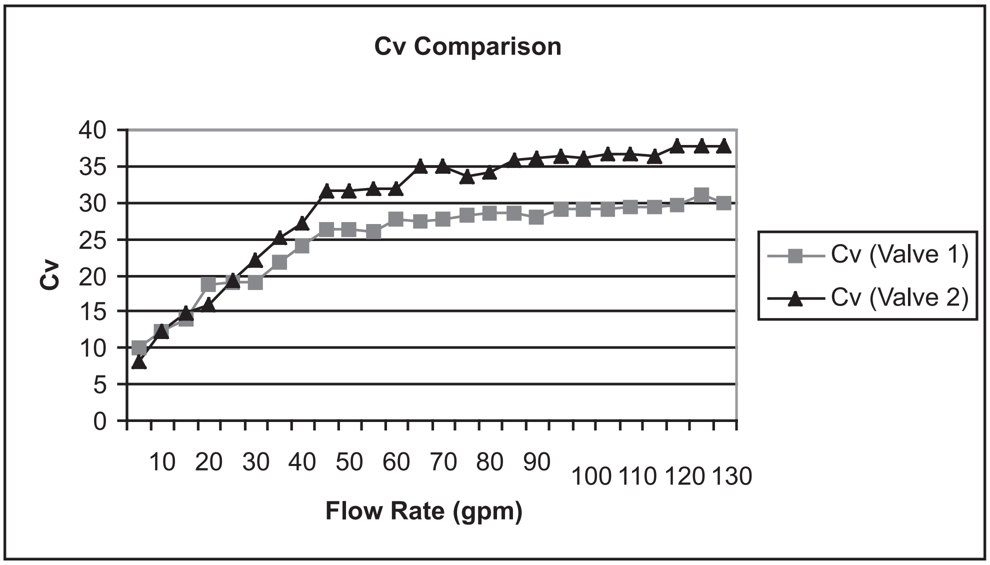


Figure 6 – Cv Comparison

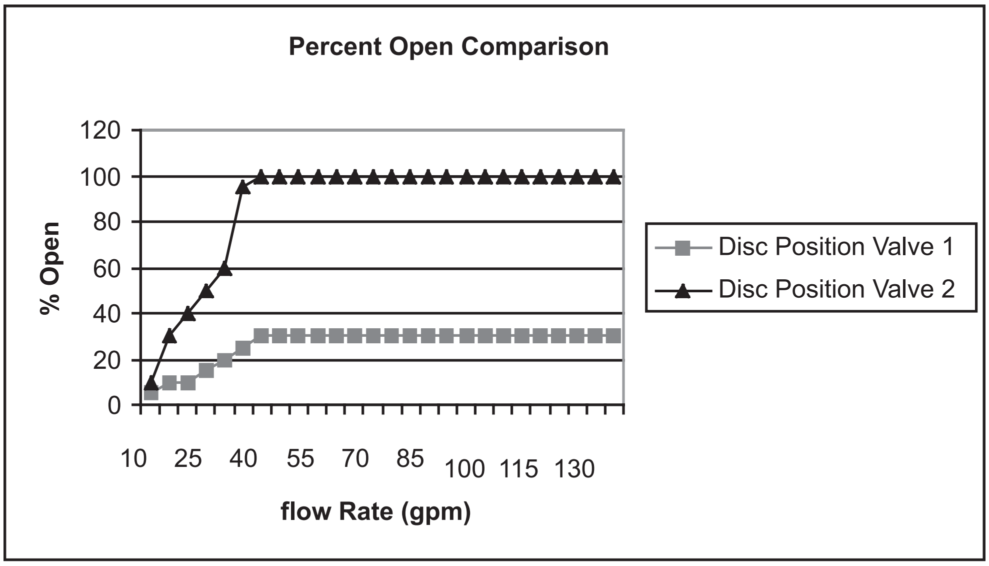


Figure 7 - % Open Comparison

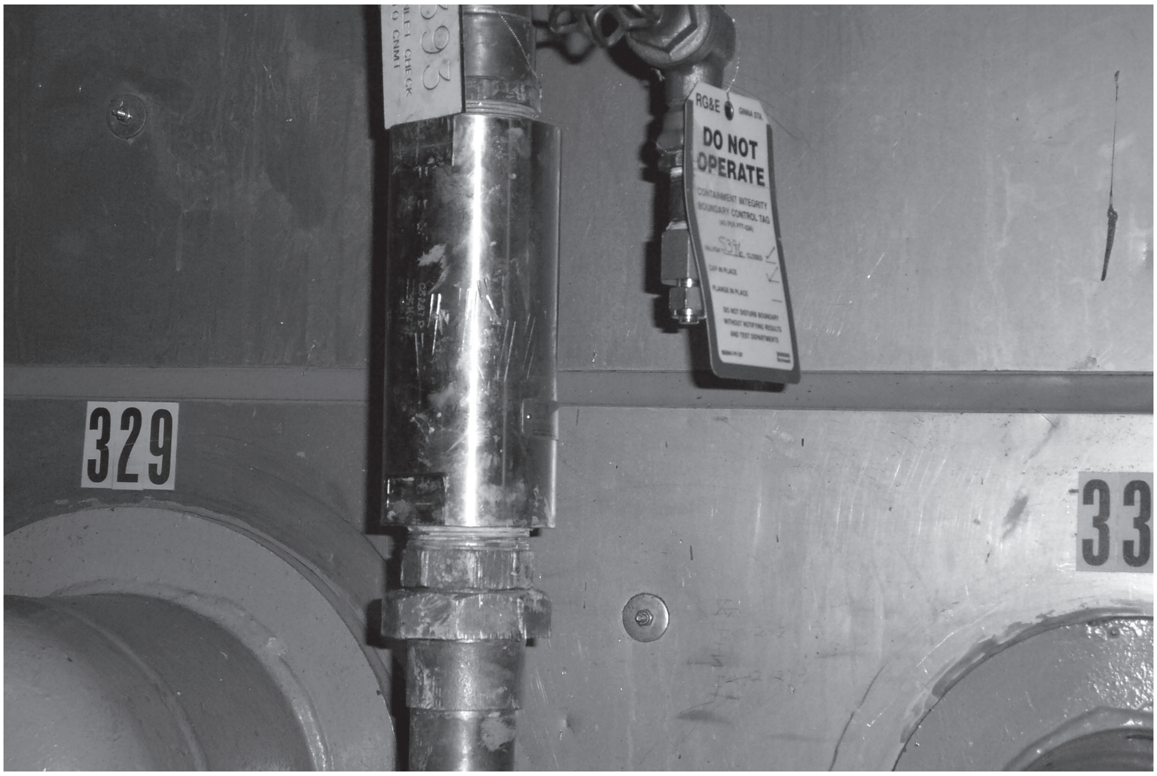


Figure 8 – ERV-Z picture installed

Lessons From Cycle Isolation Loss Recovery

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TXU Energy

Joseph G. Dimmick
Leak Detection Services, Inc.

This is an abridged version. A color copy of the complete paper in pdf format is available for downloading at www.leakdetect.com

ABSTRACT

This paper discusses how integration of several technologies enhances valve repairs. It also describes a safety problem that has been found at several plants in the course of valve testing and repair.

In a typical case, significant losses were recovered from leaking cycle isolation valves and steam traps at Comanche Peak. So far, Unit 1 output has increased by 2.8 MW and Unit 2 output has increased by 1.6 MW.

Atypical is the degree of repair success achieved at Comanche Peak by integrating several technologies in the repair process.

Two principal root causes for this leakage were identified. Generic problems were discovered such as improper body to bonnet torque causing inadequate gasket crush and the old methodology for actuator setup resulting in insufficient seat load.

The old actuator calibration technology was incapable of measuring seat load, friction band, internal binding and other critical attributes that affect seat integrity. A dynamic analyzer was used for the first time on cycle isolation valves.

At other plants, including two nuclear plants, deep cavitation pits were found by borescope downstream of leaking heater dump valves. The borescopes were used after leak testing because LDS found that heater dump valve leaks indicate the possibility of cavitation. Conventional UT is not adequate to address this problem because the cavitation is so localized. At one plant, not tested by LDS, the pit blew out under pressure, with very unfortunate consequences for the people nearby. Others have come close.

LDS recommends borescoping 20-30 times a year, and so far less than ten cavitation pits are found per year. That is a very high hit rate for a potentially severe problem.

Case histories, references and specific recommendations are presented.

EXECUTIVE SUMMARY

- Due to use of LDS equipment/services and implementing effective repairs, during a 1-year time frame (from the initial surveys until the first round of repairs were complete) a total of 4.4 MWs were recovered (2.8 MWs on Unit 1 and 1.6 MWs on Unit 2).
- The dollar value of the MWe gain achieved in the first year was approximately 10x the cost of performing the initial survey. The cost/benefit and quick payback for an initial survey should be an "easy sell" to management as long as a commitment exists to make effective repairs.
- Components were effectively and accurately categorized by leakage quantity as well as prioritized for rework by estimated energy loss.
- Due to finding block valves with no leakage (tight) conditions, some cycle isolation valves could be reworked on-line. In addition block valves with leakage could be reworked during outages to facilitate cycle isolation valve rework on-line.
- Categorization of the leakage condition (i.e.-Large, Medium, Small, or Tight) has been proven to reliably predict the type and extent of damage (soft metal/hard metal) to be reworked. Maintenance, Operations, and Engineering personnel have good confidence in the results obtained.
- Generic problems were discovered such as improper body to bonnet torque causing inadequate gasket crush and the old methodology for actuator setup resulting in insufficient seat load.

- Results from monitoring can support cost/benefit decisions on upgrading components (such as steam traps) or more thorough maintenance techniques.
- Testing can be done on any component, whether cycle isolation related or not, suspected of leakage to confirm or deny their condition and need to rework (such as ECCS/ Containment boundaries or Main Steam safety valves).
- Capabilities can be effectively developed for in-house personnel to perform monitoring and evaluate results.
- It was found that in general cycle isolation components that had been regularly monitored via temperature measurements were in better leakage condition than those not monitored regularly. The LDS testing is efficient and the results are more reliable than experienced with temperature monitoring. The scope of components to be repaired increased significantly over what temperature monitoring facilitated.
- Even though it was previously thought that cycle isolation leakage was not a significant problem, it was found that it was. This may be true at many other plants.

Introduction

Since 1979, LDS has been testing valves for internal leakage, using instruments originally developed for nuclear submarines. There have been many improvements in that time. The latest improvements produced a step increase in the success of valve repairs. They resulted from the synergistic integration of several technologies, and from the establishment of a valve task force having all of those technologies on board.

The second topic is a common hazard that we have found at many plants, nuclear and fossil.

Early in year 2000 Comanche Peak evaluated alternative cycle isolation monitoring methods to increase the scope of components monitored. Reducing cycle isolation component leakage can typically be the largest area for MWe improvement at nuclear units. Cycle isolation comprises components that can pass higher energy fluids to lower energy portions of the secondary cycle, particularly the condenser. These components can be generally categorized as:

- Normally closed valves leaking or not fully closing,
- Steam traps improperly working or degraded,
- Orifices eroded or improperly sized allowing excessive energy flow to pass through.

Comanche Peak personnel had historically been using hand held temperature instruments to perform cycle isolation component monitoring. Temperature readings were limited by insulation, failed to identify important leakers, and did not indicate what leakage was most important.

The first step was to form a valve task force. Members included planners, operators, actuator calibrators, mechanics, maintenance engineers, the performance engineer, and LDS.

Comanche Peak contracted Leak Detection Services, Inc. (LDS) to perform an initial survey on both units 1 and 2. The scope of components to be monitored was evaluated and greatly increased from previous efforts. 'Operations Troubleshooting Plans' were developed and approved to implement and control the monitoring evolution for each set of components.

Pre-Outage Survey Results

During the period 3 April 2000 -- 13 April 2000, Leak Detection Services, Inc. conducted a valve leakage survey at Comanche Peak Units 1 and 2. The objectives of the surveys on Units 1 and 2 were to identify leaking cycle isolation valves and steam traps for repair during the next outage as well as to assess the condition of block valves to determine if repairs could be performed on-line.

Before the surveys were started, an economic analysis was performed. Those valves were excluded from the survey.

We tested 739 valves and steam traps on the two units combined and found 448 to be leaking of which 239 were important to cycle isolation. We also found 291 tight valves, of which 118 were important to cycle isolation.

Table 1 summarizes the results of the April 2000 surveys of Comanche Peak Units 1 and 2.

CONCLUSIONS	LRG	MED	SML	Totals
Leaking Total	115	154	179	448
Tight Total				291
Cycle Isolation Leaks	96	53	90	239
Cycle Isolation Tight				118

Table 1 -- Comanche Peak Units 1 and 2 Combined Survey Results -- April 2000

Drip Pot Level Control Valves

LDS estimated that together drip pot level control valves (LCVs) accounted for at least half of the total cycle isolation losses. The estimate included 27 of these valves on Unit 1 and 25 on Unit 2. Of the 52 total that required repair, 45 were large leakers approaching the upper limit of our ability to measure.

Steam Dumps

There were only a few steam dump valves on the Action Reports and none had large leaks. This was favorable since steam dump valve repairs are expensive.

Actuators

Actuators are the root cause of many valve leakage problems. Several air actuators were recalibrated during initial testing but the success rate at reducing leakage was less than 20%.

Pre-Outage Severity Order Calculations

To estimate the effect of losses and repairs, calculations were made based on the Acoustic Signature Amplitude (ASA) readings from the LDS ValveAlyzer® System, the square of the nominal diameter of the item, and the differential enthalpy across the component. The results of these calculations were then summed and normalized, calculating the percentage of the total cycle isolation leakage due to each component.

Figure 2 shows the results of calculations for Unit 1. Unit 2 was similar. Drip pot level control valves accounted for most of the cycle isolation leakage.

Figure 2 reflects loss estimates. This methodology uses reasonable assumptions and a series of linear equations to approximate a complex, non-linear process. The result was a useful ordering of leaks in terms of their potential affect on cycle isolation and output.

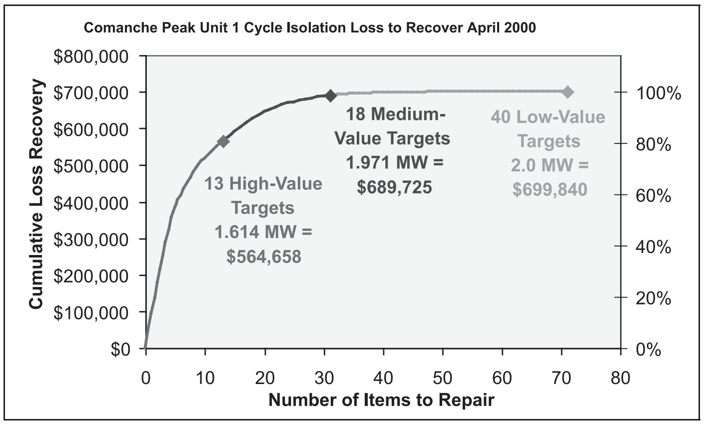

Figure 2 – Unit 1 Losses Found April 2000

The following parameters were used to calculate the results:

Nominal Rated Output	1,150	MW	Outage Interval	18	Months
Replacement Cost	$30.00	per MW-Hr	Cycle Isolation Loss	2.00	MW
Capacity Factor	90%	Annual			

Pre-Outage Survey Recommendations

LDS offered advice for specific problems based on their experience at other plants. In the case of drip pot level control valves, there were 52 of these on the Action Report of which 45 had large leaks. There was reason to believe most of them would require complete replacement, but there are some things that can be done before the outage to enhance planning. First, calibrate the actuators on all of the large and medium leakers. If many of the stem positions change as a result of that calibration, they should be retested before the outage. Second, try to inspect internally at least four of the valves on-line before the outage. The stack must be carefully measured so you will know you will get enough crush on the cage gaskets. In addition, do complete actuator and control calibration using dynamic calibration instruments before the outage and for every valve repair or replacement.

On-Line Isolation Of Worst Leakers

Temporary isolations led to MWe gains and the conclusion that permanent isolations were possible because they caused no drip pot level alarms.

- The well-publicized MWe gains from eliminating just a few leaks made all concerned even more determined to eliminate the rest of the leaks.

Temporary Isolations

Following the initial April 2000 Survey, and based on recommendations from Engineering, Operations Department temporarily isolated some of the large leakers.

No level alarms were seen. The estimated MWe gains were:

1) The 'before MSIV' (Main Steam Isolation Valve) drip pot drain line orifices and bypass AOVs were completely isolated. Unit 1 saw 0.3 to 0.5 MWe gain. Unit 2 saw 0.5 to 1.0 MWe gain.
2) The MSR heating steam drip pot drain line steam trap bypass AOVs were isolated again. Unit 1 saw 1.0 to 1.6 MWe gain. Unit 2 saw 0.7 to 1.1 MWe gain.
3) The main steam drip pot (prior to the strainers) drain line steam trap bypass AOVs were isolated. Unit 1 saw 0.7 to 0.9 MWe gain. Unit 2 saw 1.0 to 1.5 MWe gain.

These clearances were left in place either until the AOVs were worked at power or until the start of next refueling outage (when they were reworked).

Permanent Isolations of Main Steam Isolation Valve (MSIV) Drains

The initial LDS survey had identified 3 of the 4 valves in Unit 1 as having large leaks and all 4 of the valves in Unit 2 as having large leaks. Isolating both the valves and their associated orifices during normal power operation was implemented as a permanent change. A 0.3 to 0.5 MWe gain was realized by isolating these lines on each unit.

Setting Priorities

There were many valves and steam traps on the LDS action list. Short outages allow only a little time for valve work. Decisions had to be based on:

- Which were the most important,
- Which could be done only in an outage,
- Which could be attempted on-line before the outage, and
- Which could be at least temporarily avoided because their potential for output improvement was small.

Valve and Steam Trap Damage Prediction

The accuracy of planning depends on knowing the repair scope in advance. Leakers are placed on the LDS action list only if the leaks are categorized as Medium or Large. *The Large, Medium, and Small categories predict the extent of damage to be repaired.*

On Unit 1, there were 71 valves and steam traps with large or medium leaks important to cycle isolation. On Unit 2, there were 78 of these leaking valves and steam traps on the action list.

LDS estimated the severity of damage. The Large, Medium, and Small categories predict the extent of damage as follows:

- **(LRG) -- Large**. Indicates that the soft metal is being attacked. Body damage is likely. Seats and plugs may be cut deeply.
- **(MED) -- Medium**. Indicates damage to the hard metal only. Lapping is the most likely repair required.
- **(SML) -- Small**. The leak leaves no visible damage in valves, but grows larger quickly in steam traps. Take no action on valves, but repair traps.

Actuator and Controller Calibration

LDS recommended using a dynamic analyzer to calibrate before doing any internal repairs. If many of them closed tighter, retest to see if they could be taken out of the work scope.

Cycle Isolation Leakers by Valve Function

Figure 3 shows the numbers of leakers by valve function.

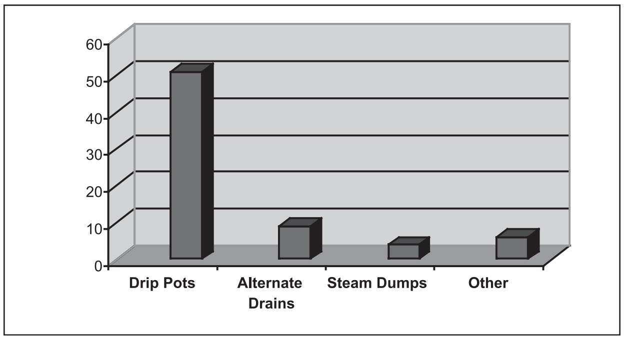

Figure 3 – Leakers by Valve Function

Drip Pot Level Control Valves
The LDS report of the pre-outage survey put the Main Steam drip pot level control valves at the top of the list for action. They were responsible for at least half of the total cycle isolation losses. All others were a distant second.

Steam Dumps
Steam dump valve leaks were not a significant contributor to the total losses. Three were found with medium leaks on Unit 1 and none on Unit 2.

Alternate Drains
There are only a few alternate drain valves on the Action Reports. On Unit 1, there are only four. On Unit 2, there are six. LDS recommended calibrating the control loops, including the actuators, because those are the most likely root causes. They are sometimes the only cause of alternate drain leakage.

Block Valves
About half of the total valves tested were block valves that were used in the process of testing cycle isolation valves. They are not directly important to cycle isolation because they are normally open, but those results determine which valves could be isolated on line and which ones would have to wait for an outage. Some of the leaking block valves were selected for outage work so the cycle isolation valves could be worked after the outage on-line.

Steam Traps
Steam traps made up about a quarter of the Action Items and none were found to be tight by testing. For these thermostatic traps, large leaks can be reduced to medium leaks but no better than that unless the design is changed to a different type such as a disk trap. Regardless, the steam traps were not very high on the priority list.

Repairs On-Line Vs During Outages

There are two reasons for reworking valves on-line versus during an outage: (1) outage time durations have decreased in order to be competitive in today's market; and (2) availability and experience of contractor support during outages.

Advantages of on-line refurbishment:

- Decreased outage scope.
- Instant thermal loss recovery.
- Plant personnel are proficient with performing maintenance on their particular valve types and are familiar with maintenance procedures.
- Repairs can be verified directly after refurbishment.

Disadvantages of on-line refurbishment

- Drip pots removed from service.
- Typically single isolation valve protection on cycle isolation valves
- Heat Stress has to be monitored on personnel.
- Extended repair time on valves that require valve body replacement.

Work Avoided

Operations personnel identified numerous Main Steam Safety valves as having seat leakage. Due to the room acoustics it is difficult to identify the valve that is audibly nosier than the others. Each steam header has five safety valves installed with the valves ranging from 2'-6" to 3'-6" apart.

Knowing the industry problems with Main Steam Safety valves sticking after refurbishment, verifying the exact valve that is leaking will eliminate unnecessary valve refurbishments and additional future testing.

LDS equipment located the valves that actually were leaking and eliminated several valves that were previously identified as having seat leakage.

Prior to every outage, the Main Steam Safety valves are tested to verify seat tightness. This method of verifying seat integrity by LDS equipment is another cost saving attribute in addition to thermal loss savings.

Rework of Valves

Figure 4 shows the numbers of different repair actions required.

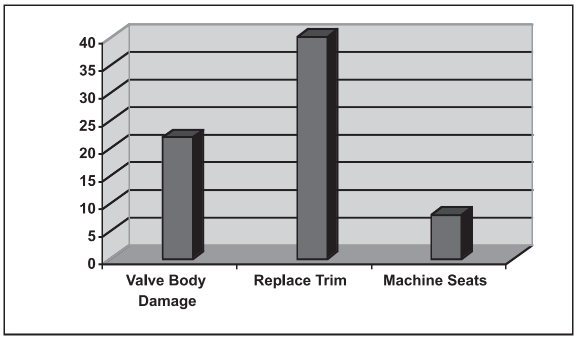

Figure 4 – Leakers by Repair required

Air Actuated Cycle Isolation Valve Rework
The LDS survey report showed which isolation valves for the Air Operated valves were leak tight. Using this information, the Air Operated valves with tight isolation valves were refurbished on-line and all others were moved into the outage scope. Approximately twenty-five (25) of the fifty-five (55) large leakers were refurbished on-line.

Initial Actuator Diagnostics
As predicted by LDS, the diagnostic tests revealed that approximately fifty percent (50%) of the actuators tested did have low bench set values and many regulators were found leaking. In all cases, adjusting the bench set did not reduce the seat leakage.

- The internal damage was already too severe.

Initial Internal Inspections
Initial inspections of the first valves worked on line confirmed the LDS predictions of severe internal damage. Seat ring and plug seating surfaces had steam cuts at the seating interface. Lower body gasket land area and adjacent areas had steam cuts and erosion. Steam cuts on plug and seat ring sealing surfaces were due to insufficient seat load during valve set up. Damaged lower gasket land was caused by inadequate bolt load due to improper torque values listed in maintenance procedures.

Large AOVs
The seat leakage on the Steam Dumps and Alternate Drains are primarily due to valve actuator set-up and instrument drift.

MS Drain Valve Bodies
LDS had predicted body damage, and numerous discontinued Fisher DBQ style valve bodies did have damage.

AOV Refurbishment Innovations

Valve bodies were measured for reference to new parts to verify correct gasket crush. Prior to and during torque application, the gap between flanges was measured with feeler gages to ensure even gasket crush is applied and final desired gasket crush was established. Torque was applied in small increments to eliminate uneven gasket crush and misalignment of valve internals that could cause increase binding or friction.

Since friction can affect critical parameters (seat load, stroke length, etc), each packing seal ring was torqued to 50% of recommended torque value during initial packing installation. Packing torque was increased in small increments until either 100% torque value was achieved or to the point friction began to affect critical parameters.

Manual Bypass and Isolation Valve Refurbishment

Inspections found disk-to-seat damage, bonnet backseat and gasket area degradation, and valve body damage.

Disks were either replaced with a new assembly or machined to restore an acceptable finish. Backseat and gasket areas were machined to the desired finish. Blue checks were performed on disk-to-seat and stem backseats to verify seat contact line.

New valves were also disassembled to verify the above criteria. New valve bodies were installed and as-left blue checks were performed to verify no seat distortion resulted during body installation.

After refurbishment, all valves were tested with LDS equipment to verify repairs.

Steam Traps

Essentially all of the steam traps showed lack of function (i.e., little to no shutoff capability) and were large- to medium-sized leaks. Considering the long time since any maintenance was performed on the traps, this presented a potential erosion concern in addition to the lost MWs.

When the replacement and maintenance costs were compared to the estimated savings there was no cost benefit to be realized. This left the concern that the traps may have suffered extensive body damage due to erosion. Evaluation of the rework costs vs. replacement costs indicated them to be very close. About 15 to 20 traps received a like-for-like replacement.

Cost-Benefit Comparison

The entire first-year cost was recovered in about four months, and the benefits have produced about $1,000,000 per year since then.

Post-Outage Tests

Post-outage performance tests

MWe gain evaluations were performed. Unit 1 was producing 2.8 MWe more than a year earlier due to cycle isolation component rework identified by the LDS monitoring. Unit 2 was producing 1.6 MWe more than a year earlier due to cycle isolation component rework identified by the LDS monitoring.

Post-Maintenance Valve Leakage Survey

After maintenance on the leakers identified by LDS, a post-maintenance ValveAlyzer test was performed to determine the success of the refurbishment. Comanche Peak had a Ninety-Eight percent (98%) success rate.

Unit 1 Post-Maintenance Megawatt Recovery

Before the outage, LDS estimated that Unit 1 had cycle isolation leakage of about 2 megawatts. After the outage, Comanche Peak reported recovery of 2.8 megawatts from reduced cycle isolation leakage.

Figure 5 – Unit 1 Cycle Isolation Leakage Loss Recovery November 2001 shows the effect of repairs on the Large and Medium cycle isolation leakers on Unit 1. A table showing individual details was also supplied.

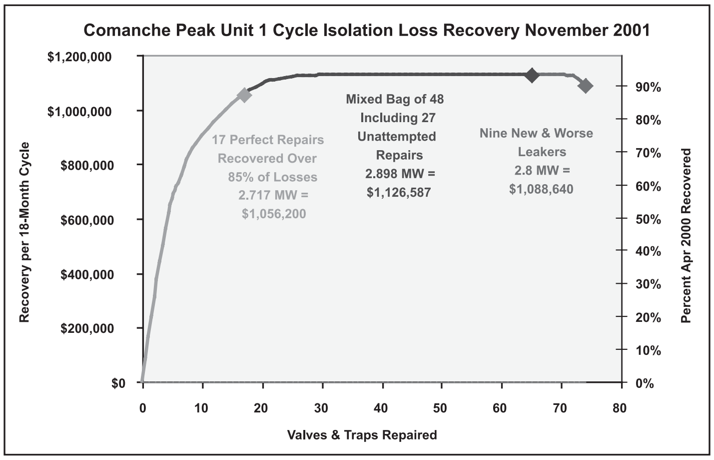

Figure 5 – Unit 1 Cycle Isolation Leakage Loss Recovery November 2001

The following parameters were used to calculate the results. Replacement cost and capacity factor are reasonable values, but are not exact.

Nominal Rated Output	1,200	MW	Cycle Isolation Loss	2.800	MW Recovered
Replacement Cost	$30.00	per MW-Hr	Cycle Isolation Loss	3.149	MW Total
Capacity Factor	90%	Annual	Cycle Isolation Loss	0.349	MW Remaining
Outage Interval	18	Months			

To put the numbers in perspective, other plants have recovered more in terms of megawatts and much more in terms of dollars, but that was due to having more losses to recover and to having much higher replacement costs in most other parts of the country.

Rarely have plants been able to do the repairs so well on the first try that they recover almost 90% of the total cycle isolation leakage.

Figure 5 clearly shows the importance of knowing not to undertake repairs that would cost more than could be gained in terms of increased output.

Actuator Calibration Improved Tightness

Actuator calibration is a frequent cause of valve leaks. If you can find a leak on a newly repaired valve with an actuator, check the actuator calibration, and correct it if necessary.

The post-maintenance ValveAlyzer test identified a Medium leaker. 2-HV-2172 is a 1.5-inch drain valve from Main Steam. After troubleshooting the actuator, the bench set was found to be low. The proper bench set was re-established and the leak was reduced to a very small leak (only successful if you catch the leak prior to cutting the seat). See traces below:

The overlay traces shown in Figure 6 directly illustrate the effect of the lower bench set adjustment.

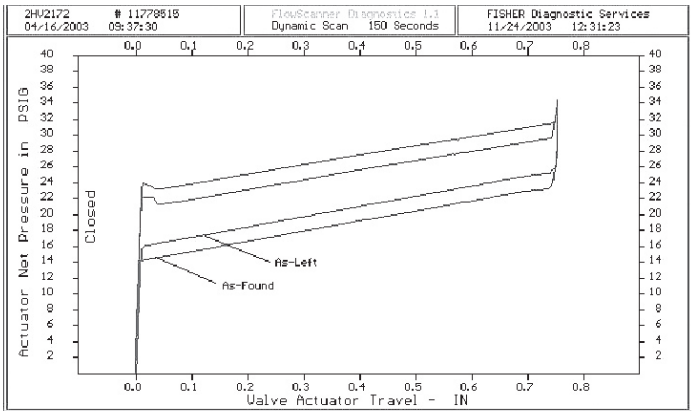

Figure 6 – Overlay Flowscanner Traces

After the actuator was put back in calibration, we recorded new signatures with the ValveAlyzer. The signature of the air-operated valve dropped by about 10 dB, while the upstream and downstream background signatures stayed about the same.

Successes

The LDS part of the process was just routine, but the degree of success by Comanche Peak was very unusual in comparison to most other plants. The differences were in teamwork and thoroughness. At other plants, disputes over budgets, manpower, control, blame and credit make teamwork difficult.

Valves are part of every fluid system in the plant, but different people are responsible for different aspects of the care and feeding of valves. No single person or organization can provide tight, functioning valves without the cooperation of other people and other parts of the plant organization.

Operators operate them and depend on them, but there are right ways and several wrong ways to operate valves. Purchasers must make sure the correct parts are available. Planners have to assign the right people at the right times. Mechanics work valve internals, but AOV techs must make sure they stroke correctly. Welders install them, but if they do it wrong, they can burn the seats at the same time. Engineers select and approve valves for each application.

Just testing the valves requires a nice degree of teamwork. The testing cannot begin until the Operations Department approves the test procedures. Operators must stroke valves, and doing that with the plant on line requires a high degree of mutual confidence. AOV testers should be available to calibrate actuators during testing. Engineers answer technical questions and count the gains, but sometimes do not want to share the credit with the maintainers. Repair funds and manpower come from the maintenance department budget, which usually does not include extensive cycle isolation valve repair. Sometimes, exceeding the previous maintenance budget has negative consequences even if there are overall gains for the plant and the company. The maintainers want part of the credit for any gains achieved, but do not want leaks to be blamed on their past work.

- Assembling the team and keeping it focused is an important job.

Powerplants in general and nuclear plants especially are extremely reluctant to commit an innovation. Most plant people feel they already know how to operate and maintain valves, and are reluctant to make changes. They are often afraid that doing something a different way means what they did before was wrong.

Before any work started, LDS spent a lot of time trying to explain what would be required to facilitate testing and get good repairs. We discussed several instances in which there was a breakdown in teamwork, with predictable consequences. Comanche Peak listened carefully, assembled a team, did all that was recommended, and then went beyond that.

Integrated Valve Team

The first different thing Comanche Peak did was to bring the entire team to a meeting with LDS. Operations, Maintenance and Engineering people were all in the same room, and the meeting took most of one whole day. The team leader made it clear that he was not interested in blame, and that there would be liberal sharing of credit to the success of the team.

There were many questions, and some of them were answered right there. Other questions were taken away to find answers later. At the end of that meeting, LDS was just one member of the team. Cycle isolation leakage was never a full-time job for any member of the team. Each team member left with a good understanding of what his part would be and what he could expect from others on the team. The original team members have stayed together and supported each other even to this day.

Root Causes and Solutions

Comanche Peak was eager to find the root causes of the leakage and to develop workable solutions to previous problems. They were not constrained to continue the old ways that had caused so many problems in the first place.

When it became clear, as predicted by LDS, that many of the worst leakers also had actuators that did not keep the valves closed, they made sure every actuator got as much attention as the valve internals.

Stems were cut, seats were cut, disks were cut, and bodies were cut under the seats, so they sought and found the root causes. Then, they eliminated the mistakes that produced those root causes of valve failure.

When they saw packing follower torque affect actuator performance, they started using the Flowscanner to find the adequate amount of torque that would not affect actuator performance.

When even newly refurbished valves arrived with inadequate gasket crush, they did their own measuring and blue checking before they installed the valves.

Best of all, they supported each other all the way.

Those innovative and thorough efforts led to a very high rate of success for repairs.

Good Working Relationship With Ops

With on-line testing and on-line maintenance in the offing, a good relationship with the operations department was essential. LDS had yet to develop the valve database and determine the test procedures required, but typical test procedures were discussed with Ops. Ops explained what paperwork was required, and LDS, working with Engineering, developed the required "Troubleshooting Plans."

The Operations Department assigned operators, sometimes two at a time, exclusively to the testing, and later to the on-line maintenance. Cranking long-stemmed isolation valves on steam dumps or alternate drains takes a lot of physical effort. They kept at it through the heat of a Texas summer, and the testing speed set a new record for a first survey at a nuclear plant.

Long discussions led first to the temporary isolation of the worst leakers, and eventually to the permanent isolation of some unnecessary drains.

Now that they are aware of the ValveAlyzer capabilities, operators sometimes request leak tests on suspected leakers before they write maintenance requests.

Early Success

The decisions to attempt on-line isolation and to do repairs on line led directly to early successes. Measurable megawatt gains came quickly, and well before the outage started. Those early successes galvanized the attention of management and the valve team.

Management Support

This is a two-way street. The team needed support from management for funding, and for keeping the members assigned. Management needed hard evidence, and soon, to support their original decision.

When on-line maintenance work was proposed, it required management support. The support flowed the other way when the team was able to document significant gains very soon thereafter.

One of the hardest things for a manager to do is to give up direct, continuous, in-line control of the people assigned to him. It makes it difficult for him to evaluate their work, and the people on the team could worry about their personnel evaluations. That was not a problem at Comanche Peak.

Confidence in Test Results

The ValveAlyzer by LDS is a proven, highly reliable piece of equipment used to analyze valve conditions. Degraded valve conditions were verified during refurbishment. All valves listed on the initial survey showed some type of degradation that caused seat leakage.

By comparing valve component damage to the decibel rating found during testing, specific component damage can be identified. This assists planning.

Spreading Credit

LDS maintains that there should be no limit to credit for a job well done. Comanche Peak was already following that philosophy. Spread praise and credit around liberally. It will come back to you multiplied many times.

To this day, each team member can recount the contributions of every other team member, without hogging any of the credit to himself. They do not have to praise themselves. The other team members and their managers do it for them. Even the managers get credit applied indirectly because of the success of the team they help flourish.

Undetected Cavitation Pits

Hazard Description

Undetected cavitation pits may exist between HP Heater Dumps and the downstream isolation valves. The danger arises if the downstream block valve to the condenser is shut, pressurizing the pipe with a hole or a weak spot. If the pit is bad enough, the piping may blow out at the pit.

Even if a large, through-wall hole exists, there will normally be vacuum in the pipe between the leaking heater dump and the condenser. Instead of blowing steam, it will suck air until the downstream isolation valve is closed.

So far, the precursors we know are large or medium leaks on HP heater dumps or feed pump recircs. We have learned of only one cavitation pit downstream from a feed pump recirc, but there have been many pits found downstream from HP heater dumps. Sometimes the cavitation is ongoing, audible, and visible on the acoustic signature, but other times it is not. The absence of current cavitation does not mean there was not cavitation in the past.

Finding a large or medium leak, hearing cavitation, or seeing it on the acoustic signature means serious damage is possible, but not certain. Even if cavitation is not ongoing while we are leak testing, it does not mean that there was not cavitation at some other time. The only way we know to make sure the damage is not there is for you to inspect the inside of the piping.

Out of 20-30 borescope inspections done at our urging annually, less than ten find cavitation pits.

Our regular clients have us test all of their HP Heater Dumps for leakage before every outage, but there are long intervals between outages. Cavitation pits could develop in the long intervals between our surveys. The units are on line while we do our leak testing, so the piping cannot be borescoped then. We do not have the facilities to borescope during outages, but you do.

Our practice so far is to do several things whenever we see large or medium leaks on HP heater dumps or feed pump recircs:

- First, we never close a block between a heater dump and the condenser.
- Second, when we find HP heater dumps leaking, we always ask that the downstream blocks be tagged open.
- Third, we try to explain that UT is inadequate for this problem because a cavitation pit is very localized.
- Fourth, we always tell people it is likely that they are hearing cavitation when banging, rattling or pinging is ongoing.

When the cavitation pit becomes a through-wall hole, a vacuum leak will start. Many plants try to localize a new vacuum leak by systematically closing downstream isolation valves to the condenser. <u>Never do that</u>. If closing the HP heater dump downstream isolation valve stops the vacuum leak, the weakened pipe could blow out at any time.

References

Some of the places where cavitation damage has been found are listed below. The people are the ones we know, but they may not be the ones most familiar with the damage found. They should know who is the most familiar.

Labadie Plant
Steam came out from under the insulation between the dump valve and the closed downstream isolation valve. The plant borescoped inside the pipe and found a large, through-wall hole obviously caused by cavitation.

Tony Balestreri, 314-992-8249

Brunner Island SES
This accident happened before our incident at Labadie, but we did not learn about it until after Labadie. A cavitation pit between the HP heater dump and the closed downstream block valve blew out while pressurized.

Paul Knapp, 717-266-7532

South Texas Nuclear Project
A cavitation hole was found in an HP heater dump. It was so bad the manufacturer could not rebuild the valve. They had to replace the valve.

Al Haedge, 361-972-8455

North Anna Power Station
LDS recommended borescoping after we found a leaking HP heater dump. A cavitation pit was found in the bottom of the valve.

Ed Thomas, 540-894-2784

Plains Escalante Generating Station
LDS recommended borescoping downstream from several leaking heater dumps. The plant found several cavitation pits downstream of heater dumps and one feed pump recirc.

Mike Marinsek, 505-876-5219

Action Recommended

Please tag open all of your HP heater dump and feed pump recirc downstream isolation valves.

Please distribute this information and try to get it discussed in safety meetings.

This is an industry-wide problem that can affect any steam unit, nuke or fossil.